Review: Status of Markets for Solar Thermal Power Systems

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Executive Summary
Review: Status and Markets for Solar Thermal Power Systems

1. Background

This document provides a high-level technical status review of the three main technology paths being pursued by DOE in the field of concentrating solar power.

In early 1999 the reviewer undertook a review of the solar dish/Stirling technology and associated markets which resulted in a report issued in mid-1999 summarizing findings and recommendations[1]. The following report is a follow on to the activities undertaken in 1999 with a focus on parabolic trough and central receiver ("power tower") technologies. The specific objectives of the study were to:

- Assess the current technology status of the technologies
- Comment on the technical/cost targets which must be met in the different market segments of interest
- Identify technology and market barriers and issues
- Provide recommendations on addressing barriers and issues

The review was done over two-month period ending on December 31, 2000. The process included a review of publicly available documents identified by DOE, interviews with major participants in the field, and judgements made by ADL based upon relevant experience.

The summary comments below are divided into two broad sections - those pertaining to the parabolic trough and central receiver technologies and those pertaining to the solar dish/Stirling option. Comments on the latter option represent a limited review on observations made in the aforementioned 1999 report on this technology path.

2. Summary Observations: Solar Trough/Central Receiver Technologies

2.1 Market Segments

Both technology options will, in most cases, compete with bulk power at the transmission line level of the electric utility infrastructure. As such, these technologies do not have the potential economic benefits of "distributed generation" which might be associated such technologies as building sited photovoltaics or fuel cells. Reasons for this observation include:

[1] Review: Status and Markets for Solar Dish Power Systems, June, 1999. Prepared for National Renewable Energy Laboratory, Golden, Colorado.

- The current strategy centers on large systems (at least 50MW for commercial-scale plants) which are too large for most distributed loads;

- The land area requirements are too large for siting systems near individual loads associated with commercial or industrial activities;

- Both the gas loads (if co-firing) and electric loads are those associated with the transmission part of the electric/gas infrastructures (as compared to the local distribution functions).

The above characteristics indicate that these technologies will have to compete with both electricity and gas at their bulk purchase rates, which will place stringent requirements on system level capital and O&M costs to be economically competitive.

2.2 Technology Status

Experience over the last decade has greatly reduced the technical risks associated with both these technology options. Specifically:

- As implemented to date, both options utilize relatively conventional steam power plant technology as the means for converting solar derived thermal energy into electricity. Advanced versions of the central receiver might use Brayton cycle technology.

- Over 300MW of solar trough technology has been operating at the Cramer Junction site in California for periods of time ranging from 10 to 15 years. The equipment has had the "usual" design related problems associated with a new technology subjected to severe environmental conditions (broken receiver tubes, mirror damage, etc.) These problems have been systematically addressed over the last decade. Most of this equipment is still being operated with increasing levels of reliability and decreasing O&M costs. This solar capacity produces electric power which is fed into the California grid on a daily basis. Experiences with these plants verifies the potential for this technology path (i.e., parabolic troughs) to achieve technical performance characteristics consistent with potential commercial viability.

- Two experimental field systems based on the central receiver concept have been operated in the United States - Solar 1 (10 MW) between 1982-1988 and Solar 2 (also 10 MW) between 1996 and 1999. Solar 1 operated for over 10,000 hours while Solar 2 operated for about 2,000 hours; a combination of technical problems with the new (molten salt-based) receiver design, operational issues, and program resource limited the run-time of Solar 2. Most importantly for both systems the heliostat fields have operated for many years (both experimental units used the same heliostats) with a level of "engineering problems" expected of new technology (i.e., not fundamental) and have verified the core assumption of the technical strategy, i.e., the ability of heliostats to reliably focus energy on a central receiver under severe environmental conditions.

The above observations indicate that the two concentrating solar power (CSP) programs have achieved an important major objective relative to demonstrating technical feasibility of CSP technology. Specifically, both strategies for generating heat from solar energy for use in power plants have reasonably well demonstrated that they can function at scales approaching those of practical commercial interest, reducing the technical risks of scale-up, particularly for the solar trough technology.

2.3. Cost Issues and Uncertainties

The review documents do not make a strong case that the cost of the technologies (particularly the solar fields) can be reduced to the point that they approach economic viability, absent large subsidies or dramatic increases in the price of natural gas.

The single most important cost elements for both technologies are those associated with the concentrator optics and associated means of absorbing concentrated solar energy and converting it into useful heat. For both technologies, these costs currently range from $200/m^2 to $260/m^2 based on current (and proven) design of major subsystems. This cost level is too high to lead to widespread use of the technologies. The review documents assert that these costs can be dramatically reduced (by roughly 50%) by some combination of:

- Larger production volumes, reducing per-unit costs;
- "Learning Curve" experience resulting from increased production;
- Improvement in the basic subsystem designs - for example, lighter weight structures, less expensive mirrors made from alternative materials, and lower cost tracking.

The "learning curve" arguments put forth lack sufficient backup to be credible given the fact that the materials of construction are already commodities and the fabrication techniques, for the most part, standard. Clearly some "learning curve" based cost reductions would be expected but unlikely at the level put forth in the review documents. Of particular importance are issues on how "learning curve" cost reductions would be distributed across the value chain (materials, factory fabrication, site fabrication, site preparation, installation) and what base of experience suggests the magnitude of such cost reductions.

The improvements in the basic subsystem designs are not well described based on engineering principles - for example, do assertions of lighter weight support structures imply that current designs are over-designed to withstand the design wind loads? Other examples might include what level of solar field savings would be expected from direct steam generation in solar troughs and why, or, better quantification of savings potential from alternative reflector surfaces.

The level of cost reduction which can be achieved while still maintaining needed performance and reliability stands as the central issue associated with assessing the commercial potential of the solar trough and central receiver technologies. Notwithstanding the above discussion, the reviewer believes substantial (to be quantified) reductions in cost are likely via a combination of "learning curve" and technology refinements. In both cases, a more transparent and disciplined approach will be needed to identify and develop the strategies leading to cost reduction and to quantify their probable impacts, in a format convincing to both private sector and government investors in the technology.

2.4. Economic Performance

The economics of CSP could approach economic viability in many regions assuming long term natural gas prices level out at above $5/MMBtu (still below recent, late 2000, prices) and modest reductions in capital costs of solar fields from current levels.

The review of economic performance based on the review documents provided is complicated by the large number of system architectures under consideration having different levels of gas co-firing, use of thermal storage, financial structures, and operational strategies. In some cases the underlying economics of the solar systems' contribution is obscured by the dominance of the non-solar contribution (i.e. gas firing) to the average generation costs.

In the current system architectures, the solar field/receivers deliver thermal energy to a steam power plant - possibly in parallel with natural gas or some other fuel. At the most basic level the economics of the solar contribution can be measured by the cost of this delivered thermal energy and how it compares with those conventional fuel alternatives. The cost of thermal energy delivered based on current field/receiver costs ($200/m^2 +) is in the range of $8/MMBtu to $12/MMBtu which is non-competitive absent significant subsidies. However, with modest solar field cost reductions, costs might approach a $5/MMBtu to $8/MMBtu range which would approach economic competitiveness with natural gas based on late year 2000 natural gas prices in the United States. If verified, this cost of delivered thermal energy could be highly competitive within the context of a changing energy supply/cost environment:

- The cost of solar delivered energy could be delivered via long-term contracts without the risks inherent in doing so with fossil fuels. Such contracts could assist electricity suppliers to mitigate fuel cost risks and demand some level of premium pricing.

- Solar delivered thermal energy would benefit from multiple state/federal incentive programs which further reduces its cost (the baseline analysis does <u>not</u> take these incentives into account).

- The use of solar delivered thermal energy by power plants reduces financial and public image risks associated with growing concerns over the increased use of fossil fuels (climate change, etc.). As a result, the "green image" derived by plant owners from by using solar as part of the input has increasing value to large corporations.

Solar field cost reductions of 20% - 40% from current levels have a reasonably high level of probability of being achieved. The above discussion suggests that so doing could make CSP an exciting prospect for large-scale implementation.

It should be noted, however, that the same analyses done a year ago (i.e. 1999) would have concluded that the CSP option was far from economical even with substantial cost reductions!! This points out the overriding importance of the assumed costs going forward of natural gas (and other fuels) and how this cost will vary by region of the world.

2.5. Operations and Maintenance (O&M) Costs

Any changes in the design of the solar field to reduce capital costs must be consistent with further reductions in O&M costs (certainly no higher).

Operations and Maintenance costs have been and continue to be large concerns for all CSP technologies, given the large areas of high precision equipment subjected to severe environmental conditions (wind, dust, hail, etc). O&M costs are divided into three main categories:

- Cleaning of the critical reflective surfaces
- Replacement of broken parts
- Management of the plants and processes

Over the past decade, system operators have realized significant improvements in the O&M cost structure of CSP technologies most notably that of the parabolic trough systems where over a decade of experience has reduced the O&M by a factor of two to three. The solar field O&M costs are currently \$13 - \$18 per m^2 per year which translates into roughly \$3/MMBtu to \$5/MMBtu of delivered thermal energy (~ \$0.04/kW-h with the power system architecture used). The cost structure is divided approximately evenly among the main O&M cost elements listed above.

Structured analyses of the primary elements of O&M cost structure indicate that further reductions of solar field O&M costs to the \$5 to \$9 per m^2 per year range can be expected with reasonable confidence assuming any design changes to reduce capital costs do not significantly impact on the "cleanablity" of the critical reflective surfaces or the breakage rate of subsystems (reflectors, receiver tubes, etc).

So doing would reduce the O&M cost portion of delivering thermal energy to under \$1.50/MMBtu (under \$0.02/kW-h in the power plant). Achievement of the lower O&M figures will be critical to overall economic viability.

2.6. Conclusions/Recommendations

As a result of over twenty years of government and industry support, CSP technology has demonstrated its technical potential to reliably deliver solar derived heat to conventional steam power plants even when operating under severe environmental conditions. The key issue issues are converging to:

- The ability to significantly reduce the cost of the solar collector/receiver subsystems from those associated with the current field systems without compromising efficiency, reliability, and O&M requirements;

- The projections for the longer term cost of natural gas in the United States and other regions considering CSP.

Based on late year 2000 natural gas prices (in excess of $6/MMBtu), CSP show potential for delivering thermal energy to power plants at costs which, at least, approach those of natural gas. Other factors such as environmental benefits, energy security, and long-term price stability would add further to the interest in such an option and enhance the possibilities for larger-scale use.

To date, the ability to achieve the needed cost reductions has not been well positioned in the review documents, nor supported by engineering based analyses and verified by appropriate testing. Clearly articulating a detailed and plausible research, development and deployment path towards attaining the targeted cost reductions would significantly increase the interest in CSP technology options in both the energy industry and the investment community and help ensure that CSP becomes one of the options for addressing future energy needs. As such, any program going forward must focus on establishing the cost reduction potential to the satisfaction of potential investors in the technology and the overall energy community (including political) which must be convinced that CSP has the potential to be more than an engineering success.

3.0 Solar Dish Systems

The technology and market issues for solar dish/Stirling engine based CSP systems were reviewed in a report provided to NREL in mid-1999, Review: Status and Markets for Solar Dish Power Systems. The following is a very brief summary of some of the important observations from that report and, as appropriate, a comparison of the solar dish technology option with the trough and central receiver technologies which was the focus of this work.

Technology Description:

The solar dish system utilizes a solar concentrator (roughly 11 m in diameter) to focus solar energy on the heater head of a Stirling engine for the production of power – about 25kW under rated conditions. The solar concentrator requires technologies which are similar to that used in the heliostats of the central receiver options, i.e., two axis tracking of precise reflector surfaces with sufficient rigidity to withstand design wind loads. As such the cost of the solar dish concentrators should be similar (perhaps 10 to 15% higher due to more complex geometries) to heliostats assuming similar production volumes and installation procedures.

As indicated above, the current dish concentrator systems utilize a kinematic Stirling engine to convert heat into electric power. Such engines have several highly desirable characteristics in this application including high efficiency and potential for low cost at moderate production levels. The primary drawback to date is that the Stirling technology has not demonstrated the required life and reliability characteristics for use in commercial systems. For example, the longest operating time for single engines is on the order of 7,000 hours which is about 2 to 3 years of solar operation. Significant progress is being made in improving (and verifying) Stirling engine life/reliability characteristics which, if successful, will make the prospect for the solar dish/Stirling engine option similar to that of the other CSP options.

Market Characteristics:

In principle, solar dish/Stirling systems could be implemented one module at a time or in multiples to achieve any power level – for example, one system would provide 25kW peak while a cluster of 10 modules could provide 250 kW peak. This is in contrast to either the central receiver or parabolic toughs which in current configurations are targeting application with capacities in excess of 30MW. The dish systems could, therefore, address many of the high value distributed power markets in both developed and developing countries which are now the focus of the PV industry. There are several questions, however, that have been raised relative to the practical ability of solar dish/Stirling systems to cost effectively address disperse loads:

- The marketing, transportation, and installation of solar dish systems will be high when undertaken in small numbers in remote locations and require an appropriate infrastructure to do effectively.

- The systems are operationally complex (compared to PV) and would require a highly trained infrastructure of O&M staff to attain the required reliability for operation in remote areas. Implementing such an O&M infrastructure for dispersed system will be costly – at least in the early years.

Due to the above factor, the developers of the solar dish/Stirling engine systems are directing most of their attention to larger multi-megawatt installations (hundreds or thousands of modules) in order to gain the same manufacturing, installation, and O&M economies of scale as the trough and central receiver options.

Special Characteristics:

As indicated above, the solar dish/Stirling engine approach to CSP would have similar economics as the other two strategies (assuming successful commercialization of the Stirling engine) and, currently are addressing similar markets. The primary technical difference is that the trough/central receiver systems use conventional technology for converting solar heat into power thereby avoiding a significant element of technology risk.

A practical advantage of the solar dish/Stirling engine option is, however, the potential to install systems incrementally over time – even when implementing large projects. For example, a twelve megawatt project (480 modules) could be implemented over a period of one year (40 modules per month) with power generation (and income) starting after one month or less. So doing reduces project technology risk, results in near term income, and reduces the interest during construction element of project financing.

The ability to implement large projects on an incremental basis provides the solar dish/Stirling engine approach to SCP with interesting differentiation from the tough/central receiver system architectures which are not conducive to such a strategy.

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Objectives

Provide an independent overview of the current status and commercialization issues of concentrating solar power technologies.

- Address at a "high level" three CSP technologies:
  - Trough Electric
  - Central Receiver ("power tower")
  - Dish/Stirling*
- Assess the current technology status and market potential in U.S. and internationally.
- Identify technology and market barriers - recommend strategies for addressing barriers

*This presentation primarily addresses trough and central receiver technology. The status/issues associated with Dish/Stirling were reported in a June 1999 report submitted to NREL "Review: Status and Markets for solar Dish Powre Systems, Arthur D. Little, Inc., June, 1999"

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Process

The review was done over an eight week process (from November/December, 2000).

- Review of literature (25 + documents) pertaining to the solar power technologies under consideration
- Interview (15) with experts at Sandia, NREL, DOE, ad industrial organizations involved in the development process
- Visit to Sandia Laboratories for a mid-term review and discussion of issues

Information from the above was synthesized with extensive ADL information and database pertaining to solar technologies and markets.

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Siting Considerations

- The reflective concentrator elements of CSP systems are ground mounted and have high visual impacts - a characteristic shared by most other tracking systems including those using photovoltaics
- The high profile and substantial land area requirements of the CSP systems places constraint on where such systems can be sited and will significantly impact market potential (even aside from economics) in some applications (on-site power for commercial buildings, substation support in urban/suburban areas, etc.) where land area availability and aesthetics are important issues

Solar Availability

- CSP utilize only the direct component of solar radiation (common to all concentrator systems)
- In arid sunny regions (Phoenix) direct radiation represents 76% of total while in many humid (but high overall solar regions such as Miami) the direct radiation often reduces to 65-70% of total
- This characteristic results in CSP systems having target markets focussed on sunny (relatively dry) regions - primarily the southwest in the United States (and similar areas in LDC's - for example Mexico, North Africa, etc.)
- The geographical target areas tend to be more limited than for flat plate PV which utilizes total solar radiation (i.e., not just direct)

However

- The areas most suitable for CSP systems are among the fastest growing in the country (and the world) and would provide potentially large, high impact, markets for decades to come if the technology meets cost/ performance requirements

Market Segments/Requirements Market Segment Identification

The market segments for CSP systems can be roughly divided between grid connected and non-grid connected:

Grid Connected

Application	Typical Capacity Range	Conventional Alternatives
Commercial/Industrial Buildings (site based)	25 kW - 1,000 kW	Grid Power (at retail)
Substation Support	1,000 kW - 5,000 kW	Grid Power (at substation)
Central	30 MW+	Busbar Power

Non Grid Connected (primarily developing country)

Application	Typical Capacity Range	Conventional Alternatives
Water Pumping: (irrigation)	5 kW -200 kW	◆ Diesel engines ◆ Gasoline engines ◆ Grid extension
Rural Electrification	5 kW - 500 kW	◆ Diesel generators ◆ Grid extensions
◆ Special Functions ◆ Refrigeration ◆ Desalination	5kW - 200 kW	◆ Diesel engines ◆ Grid extensions

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CSP Technologies: Markets/United States

With the current development strategy, both solar trough and central receiver technology will be competing with bulk power and natural gas at the transmission line level:

- The current SEGS systems were installed 50 MW blocks
- The review documents all refer to even larger systems (both trough and central receiver) as do the projects under consideration worldwide
- In the U.S. such systems would need to be located in favorable solar areas of the southwest in relatively remote locations (due to large requirements for low cost land)
- Connection with low-cost gas supplies and electrical interconnect for such blocks of power would be at the transmission line level where the basis of competition is bulk power and transmission level gas prices (as compared to prices with local distribution systems)
- In their current form, solar trough and central receiver technologies are not a “distributed resource” which can be placed within a T&D system at locations selected based on relieving T&D constraints on improving power quality (as might a packaged gas turbine of similar capacity)
- This places large scale CSP technologies in direct economic competition with the lowest cost supplies of electricity and natural gas

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With the current technology strategy, both central receiver and solar trough technologies will need to be part of the central grid in most LDC.

- One presumed advantage of solar power for use in LDC is that it can be placed in remote locations thereby avoiding the high costs associated with serving rural loads (a major strategy for the PV industry)
- This advantage is not likely to be associated with solar trough/central receiver technologies in their current form:
  - Most rural loads in LDC (villages, agriculture, etc.) are measured in 10's and 100's of kW (maybe low MW) so that the capacity of trough/central receiver systems are far too high!
- As a practical matter, therefore, solar troughs in LDC will usually be competing with central grid bulk power/fuel supplies similarly as in the U.S.

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Assessing the economics of CSP technologies is complicated by number of system architectures under consideration.

- The review documents describe a wide range of overall system architectures integrating in various ways:
  - Solar derived thermal energy
  - Natural gas thermal energy
  - Energy storage (thermal)
  - Steam Power plants
- Depending on architecture details (for example, the percentage of energy provided by solar), the overall system (conventional + solar) economics can vary greatly
- The above factors tend to obscure the underlying economics of the solar contribution

The "cost" of solar thermal energy was used as a parameter to assess economics:

- In most systems the concentrator/receiver field is providing heat energy to a "conventional" steam power plant
- Most systems operate with a combination of solar and natural gas (or other hydrocarbon) fuel input with the solar portion depending on overall design strategy
- In most cases, the power plant could be operated with natural gas (or some other fossil fuel) without solar - as such, one reasonable measure of solar economics is how its cost of delivering thermal energy compares with natural gas (i.e. they are competing fuel alternatives for the power plant)

CSP: Cost of Energy

A simplified form of levelized "cost of energy" (COE) analyses was undertaken to estimate the cost of delivered thermal energy from CSP technologies.

- This report uses a simplified form of a levelized COE derived from EPRI TAG methodologies

$$COE = \frac{CR \times \text{Capital Cost}}{\text{Annual output (kWh)}} + O\&M$$

- CR is the "capital recovery factor" and takes into account such factors as interest on dept, equipment depreciation, return on investment, insurance, and taxes
- Prior experience indicates the CR tends to fall in a range of 0.10 to 0.16 for well established technologies where no special risk factors are involved

CR = 0.10: Might correspond to situations with concessionary financing as exemplified by projects involving government and/or international donor participation

CR = 0.16: Might correspond to more common commercial terms as exemplified by private developers and merchant power plants

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The potential for future cost reductions need to be verified:

- The "current" cost for the heliostat field is about 200/m^2 - 260/m^2
- This cost is consistent with that for other solar concentrator systems and recent experience in mounting 1 X PV tracking systems.
- The review material indicated cost reductions to roughly half these levels (\$100/m^2 - \$125/m^2) - rationales cited (with limited support) include:
  - Learning curve effects of increased production
  - Lighter weight support structures
  - Lower cost mirror assemblies
  - Lower cost receiver tube assemblies

Parabolic Trough: Cost Structure

Reviewer observations on the status of cost reduction potential:

1. "Learning Curve" effects
   - Most materials of construction already are commodities with limited room for cost reduction absent major design changes (I.e. volume alone will have limited impact)
2. Lighter weight support structures
   - No data presented suggesting current structures are significantly over designed given severe environmental conditions and rigidity requirements
3. Lower cost mirror assemblies
   - To date, only silvered glass has demonstrated the combination of high reflectivity, optical smoothness, cleanability, and durability needed for this application. All other options remain to be proven

- In summary, some level of cost reduction likely - the level of which cannot be estimated with confidence absent a combination of technical/cost analyses and experimental verification of specific designs

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Parabolic Trough: Economics

A range of technical and financial parameters was utilized in the economic analyses of parabolic trough systems.

Technical Parameters:

- Trough field efficiency (annual):
  High = 50%
  Low = 44%

Cost Parameters:

- Trough field capital cost: $300/m² ⟶ $100/m²
- O & M cost: (% of capital investment per year)
  High = 1%
  Low = 0.5%
- Financial Parameters:
  Conventional Financing: CR = 0.16
  Concessional Financing: CR = 0.10

CR = Capital Recovery Factor

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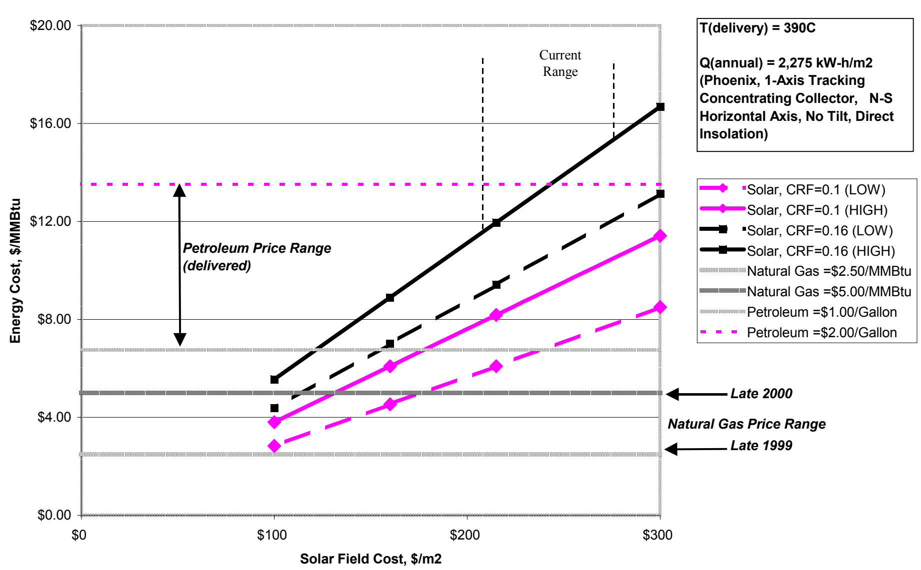
Solar Trough: Solar (No Parasitics), Natural Gas and Petroleum Energy Cost Comparison



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Parabolic Trough: Economics

The cost of thermal energy from parabolic trough fields might "approach" being economically attractive under some conditions.

- At current solar field costs (~\$200-\$250/m^2), the COE with conventional financing would be \$8/MMBtu and \$14/MMBtu which is considerably higher than natural gas (on average)
- Solar field cost reductions to \$130/m^2 to \$160/m^2 combined with favorable financing would reduce the COE to the \$5/MMBtu to \$7/MMBtu range which is comparable to late year 2000 gas costs
- It should be emphasized, that 1 year ago (1999), the cost of gas was \$2-\$3/MMBtu so that the economics of solar troughs have significantly improved due to external factors
- A key issue is, therefore, what assumptions relative to natural gas costs should be assumed in assessing economic potential!!!

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Central Receiver: Economics

A range of technical and financial parameters was utilized in the economic analyses of the central receiver option.

Technical Parameters:

- Heliostat field efficiency (annual):
  High = 45%
  Low = 35%

Cost Parameters:

- Heliostat field capital cost: $300/m² → $100/m²
- Tower/Receiver costs: $20/m² of heliostat area
- O & M cost: (% of capital investment per year)
  High = 3%
  Low = 1%
- Financial Parameters:
  Conventional Financing: CR = 0.16
  Concessional Financing: CR = 0.10

CR = Capital Recovery Factor

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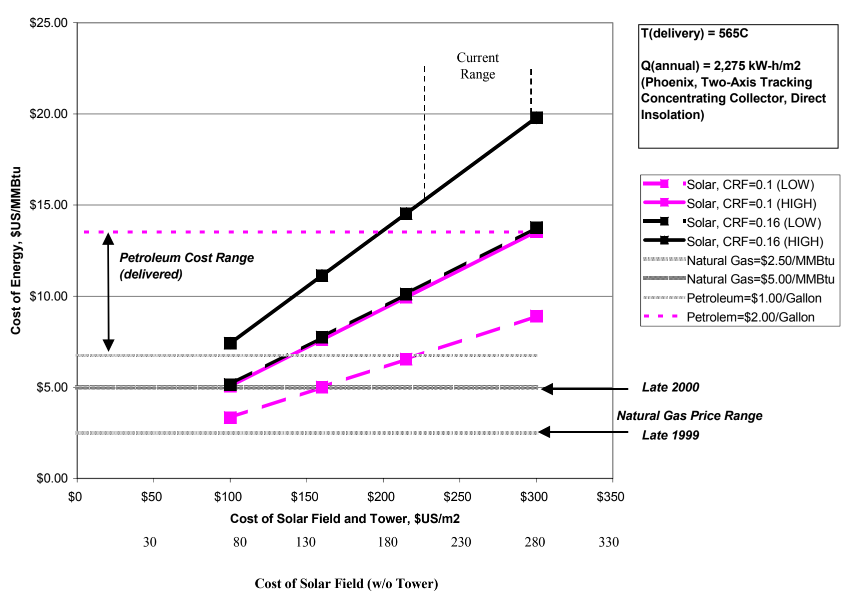
Central Receiver: Solar (No Parasitics), Natural Gas and Petroleum Energy Cost Comparison



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The cost of thermal energy from heliostat fields might "approach" being economically attractive under some conditions.

- At current solar field costs (~$200-$250/m^2), the COE with conventional financing would be $10/MMBtu and $15/MMBtu which is considerably higher than natural gas
- Solar field cost reductions to $160/m^2 combined with favorable financing would reduce the COE to about $5/MMBtu - $7/MMBtu which is comparable to late year 2000 gas costs
- It should be emphasized, that 1 year ago (1999), the cost of gas was $2-$3/MMBtu so that the economics of solar troughs have significantly improved due to external factors
- A key issue is, therefore, what assumptions relative to natural gas costs should be assumed in assessing economic potential!!!

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APPENDIX A

PCAST Reference --

High Temperature Solar Thermal

Federal Energy Research and Development for the Challenges of the Twenty-First Century

Report of the Energy Research and Development Panel by the President's Committee of Advisors on Science and Technology (PCAST)

November 5, 1997

Table 6.1: Proposed R&D Budgets, Activities, and Impacts (in millions of as spent dollars).

Activities are to be carried out through industry/national lab/university partnerships with cost sharing by industry. The focus is on R&D activities, with some precommercialization demonstrations. Commercialization activities are considered separately in Chapter 7. All activities indicated here as "co-supported" by ER are for fundamental research activities that are to be both cofunded and comanaged by the particular energy technology program and by ER in the manner and under the conditions described in the R&D management section of Chapter 7; support from ER would come from new funds or funds made generally available as programs normally turn over.

Note that many of the following budgets will ramp down in the 2005-2010 time frame as the largest portion of the potential cost reductions is achieved and the embryonic renewable energy industry strengthens. In all cases, budgets are to be re-examined periodically for performance and adjusted accordingly.

Technology	**R&D activities beyond current baseline, and impacts**	**FY97 $M**	**FY98 Reqst**	**FY99 $M**	**FY00 $M**	**FY01 $M**	**FY02 $M**	**FY03 $M**
Biomass: Fuels	Double number of energy crop species under development; develop crop harvest, handling, storage systems. Stimulate fundamental research on perennial species with co-support from ER at up to $2M. Develop integrated power/ethanol plant with goals of: cost of ethanol at $0.50/gallon and power at $0.04/kWh; and producing 28 billion gallons ethanol/year and 36 GW of capacity by 2020. ER to co-support key fundamental research relating to ethanol production at up to $5M level. Launch modest program to produce biofuels from synthesis gas.	28	38	58	76	94	97	99
Biomass: Power	Develop biomass—materials handling; IGCC; biogasification-fuel cell; small-scale gasification-stirling engine or other systems; cofiring with coal; and other systems with associated cost-shared precommercial demonstrations. Goal of 6 GW in pulp and paper industry by 2010; 25 GW cofiring by 2030. Integrated power/ethanol plant as above. Cofiring to be cost shared with DOE fossil energy program.	28	38	63	86	89	91	93
Geothermal	Reactivate R&D on advanced resources, especially HDR; expand advanced drilling R&D through NADET; increase R&D on reservoir testing and modeling, increase productivity, lower costs. ER to co-support fundamental reservoir engineering science—including geophysics diagnostics and modeling, formation charaterization and fracturing for HDR,etc.at up to ~$5M.	30	30	42	49	50	51	52
Hydrogen	Program should move away from near term demonstrations in internal combustion engines. Launch initiative with DOE Fossil Energy program on innovative hydrogen production from fossil fuels combined with sequestration and with the Biofuels program on hydrogen production from biomass—additional budget for hydrogen research ramping up to $15M/year, consisting of comparable contributions from the biofuels program, the fossil energy program, and ER. ER would co-support research on advanced hydrogen storage technologies (e.g., carbon nanostructure materials) and other fundamental science issues at up to about $5 M.	15	15	16	16	17	17	17
Hydropower	Accelerate R&D to develop fish-friendly turbines and low-head run-of-river turbines; analyze ecological/environmental impacts of hydro on a quantitative basis; examine coupling of hydro to intermittents; examine innovative financial instruments for funding activities through PMAs.	1	1	4	8	11	11	12
Photo-voltaics	Accelerate fundamental PV science—understand properties of PV semiconductors, broaden range of materials investigated, and discover new PV materials, with co-support from ER at up to $5 M. Substantially strengthen laboratory scaleup to first-time manufacturing, including reaction kinetics and reactor design, large area uniform deposition and quality control under volume production. Support engineering science for large volume, low cost production, including increased deposition rates, improved materials utilization, improved characterization techniques—especially in situ, and materials recycling. Support for system integration and BOS work—particularly to improve inverter technology cost, performance, and reliability.	60	77	105	130	133	137	140

Solar Thermal	Strengthen power tower and dish-stirling technology development, including molten salt storage and optical materials research, and solar manufacturing technology initiative. Launch new initiatives in advanced high temperature receivers, brayton cycles, and fuels production. Co-support from ER at up to about $5 M for study of radiation-matter interactions at high solar fluxes and high temperatures, materials science relating to high-temperature STE technologies, and materials science relating to the development of low-cost reflectors.	22	20	32	43	44	46	47
Wind	Strengthen R&D in advanced 3-D computational fluid dynamics, fundamental R&D on advanced materials for blades, lightweight adaptive structures to passively reduce loads and extend fatigue life, direct-drive variable speed generators, hybrid systems, system integration—especially with large-scale storage systems or hybrids, advanced controls, etc.; and conduct field tests, particularly in collaboration with developing countries. Launch strong wind manufacturing technology initiative. ER to co-support materials, computational, and other research at up to about $5M. Conduct research in environmental issues, particularly avian.	29	43	53	65	66	68	70
Systems and Storage	Extend storage R&D, particularly for system integration with intermittent renewables; conduct highly leveraged test of CAES with wind. Develop R&D program on T&D	32[a]	46	51	54[b]	55	57	58
Solar Buildings	Expand R&D: in efficient/passive whole building design; building-integrated PVs and thermal systems; low cost solar water heaters and other thermal collectors. Develop building energy and materials design tools. Support international buildings R&D and design tool development. ER to co-support basic materials studies at up to about $2.5M—temperature/UV resistant polymers for low cost thermal collectors; phase change storage materials; electrochromics	3	4	6	9	9	9	9
Interna-tional	R&D in applications-specific systems integration and development; international collaborative R&D; technical and policy analysis; technical assistance; training	1	7	11	13	13	14	14
Resource Assessment	Integrated resource assessment across biomass, hydro, geothermal, solar, wind, and CAES; further develop geographic information systems; develop advanced resource mapping tools and techniques, Systematically extend resource assessment studies to developing countries.	(1)	--	5	5	6	6	6
Analysis	Strengthen program focus on and conduct systematic analyses of technologies—distributed utility systems, minigrid systems, systems integration and intermittent integration with utility systems; and of strategic analysis of technology opportunities within regulatory restructuring. Extend analysis of markets—financial analyses, options valuation; and of policy mechanisms—net metering, green pricing, portfolio standards, economic impacts; externalities, etc.	(3)	--	4	5	6	6	6
Other	Renewable Energy Production Incentive; Solar Tech Transfer; Renewable Indian Energy Resources; Program Direction; and others. These activities were not examined by the Task Force and are included here as a constant baseline only for consistency with budget documents.	21	26	25	26	27	26	29
TOTAL		270	345	475	585	620	636	652

[a]This is the FY97 level and does not include the increase from FY97 of $19.75M to $36M for superconductivity already agreed to by both House and Senate in the FY98 budget.
[b]Superconductivity R&D remains at $32M; EMF R&D from $8M to $0; Storage R&D from $4 to $12M; T&D from $0 to $10M.

High-Temperature Solar Thermal

High-temperature solar thermal technologies use mirrors to concentrate the sun's rays onto receivers, in which the solar heat is recovered. The DOE Program is aimed at developing solar thermal electric (STE) systems that make electricity from the recovered solar heat in conventional thermal power cycles.

Technology Attributes

STE systems have the long-term potential to provide a significant fraction of the world's electricity needs; however, because these systems can use only direct rays from the sun, they must be located where there is good direct normal insolation with minimal cloud-induced scattering, e.g., the southwestern United States, the Middle East, and desert areas of many developing countries.

STE applications range from central-station to modular, remote power. STE systems can be hybridized to run on both solar energy and fossil fuel; they can also be designed with integral thermal energy storage that can make solar-only STE systems dispatchable.

Hybrid systems in which solar heat is used to provide modest (10 to 20 percent) contributions to steam generation in fossil power plants (NGCCs or coal plants) make it possible to (1) gain valuable commercial experience with STE technology and build up STE industrial capacity in the context of familiar conventional generating technology, (2) exploit economies of scale for the power conversion technology without risking large solar investments, and (3) increase the value of the generating capacity to the utility and thereby increase the electricity rate the utility is willing to pay for electricity generated.

Environmental Issues

Air pollutant and GHG emissions are associated only with the fossil fuel fractions of hybrid STE systems. STE plants would be no more land-use intensive than some coal plants. Water supply availability could constrain development in water-scarce regions if wet cooling towers are used, but this problem could be addressed various ways (e.g., by using completely dry conversion technologies such as regenerative gas turbines).

Present Situation

The only STE technology with commercial experience uses parabolic trough collectors coupled to steam turbine power units and natural gas backup; some 354 megawatts was installed in California, 1984 to 1991; as a result of this experience capital costs for the solar portion fell from $4500 to $2900/kW. The company involved had to file for bankruptcy in 1991, largely as a result of the on-again, off-again extension of tax and regulatory incentives. Today vendors are pursuing new projects in several countries. These plants will be able to produce solar electricity at life-cycle costs in the range 13 to 14 cents per kWh for the solar portion of the produced electricity (assuming corporate financing)—low enough to compete in some load-following and peaking-power markets.

The DOE Program

The STE program is developing advanced technologies cooperatively with industry, which has shown strong interest by its involvement in cost-shared projects averaging a 45 percent industrial contribution. Goals for 2020 are 5 cents per kWh solar electricity and 20 GW_e of installed capacity worldwide. Both the "Power Tower" (PT) that uses a field of heliostat mirrors to concentrate sunlight onto a centralized receiver and the parabolic dish (PD) that focuses sun rays onto receivers mounted at dish foci are being developed.

PT technology is being developed at scales of 100-200 megawatts for central stations; PD technology at scales of 5-100 kilowatts for distributed markets, especially developing country markets. PT R&D involves developing low-cost heliostats and associated drives, high-temperature receivers, and high-temperature molten nitrate salt thermal storage, and understanding system integration issues. Thermal storage makes it possible to decouple solar energy collection from its conversion to electricity and to provide dispatchable power. If heliostat cost goals are met, PT technology with approximately 13 hours of storage could provide, by 2020, 5 cent per kWh baseload solar-only electricity.

At present estimated electricity costs are higher for PD than for PT technology; but future costs might be comparable, if hoped-for economies of mass production are realized. PD R&D is focused on developing low-cost, reliable concentrators and on using energy-efficient Stirling engine electric generators; however, realizing low maintenance costs and long system lifetimes are major R&D challenges for these engines.

Assessment and Recommendations

The program is well structured to meet the challenges of developing the targeted technologies and well-coordinated with industry. Emphasis on molten salt storage, a key enabling technology, is appropriate. The refurbishing of the 10 megawatt Solar One pilot plant (in Barstow, California), which successfully proved the PT concept as a workable STE technology, into Solar Two as a test-bed for molten salt-based PT technology is key to understanding systems integration issues before building commercial-scale demonstration plants. **Development of low-cost thin-film reflectors for use in both heliostats and dish receivers warrants high priority. SolMat, a new initiative to help develop manufacturing techniques, could prove to be as important as PVMat has been for PV technology.**

The program's major shortcoming is inadequate attention to the possibilities for achieving higher efficiencies and lower costs by operating receivers at higher temperatures that could accommodate gas turbine cycles. **Pursuing higher temperature technology would require adding to the Program new heat transfer fluids, receiver concepts, and storage concepts; strong ties with ER in radiation-matter interactions, materials research, and thermal storage at high temperatures are needed. The program should work closely with DOE Fossil Energy (FE) to develop appropriate gas turbine cycles. It should also pursue collaborative R&D efforts with foreign STE R&D groups, several of which have strong efforts underway on advanced high-temperature receivers; these collaborations could include advanced systems studies, component development, and the construction of pilot plants designed to explore systems issues. Finally, the Program should be broadened to include fuels production by using high-temperature solar heat to drive endothermic reactions. In particular, the STE and H_2**

programs in EERE and FE should collaborate on high-temperature receiver development suitable for making H_2 from fossil fuels and the associated high-temperature chemistry research.

These activities require expanding the budget from $22 million to $47 million per year (see Table 6.1). The increment should include funding at a level of up to about $5 million per year, with matching funding from ER, for fundamental research on science issues related to high-temperature receivers and materials science issues relating to the development of low-cost reflectors for both heliostats and dish receivers. This fundamental research should be both cofunded and comanaged by the STE program and by ER in the manner and under the conditions described in the R&D management section of Chapter 7.

APPENDIX B

DOE/EPRI Technology Characterization

DOE/Electric Power Research Institute Technology Characterization

OVERVIEW OF SOLAR THERMAL TECHNOLOGIES

Introduction

There are three solar thermal power systems currently being developed by U.S. industry: parabolic troughs, power towers, and dish/engine systems. Because these technologies involve a thermal intermediary, they can be readily hybridized with fossil fuel and in some cases adapted to utilize thermal storage. The primary advantage of hybridization and thermal storage is that the technologies can provide dispatchable power and operate during periods when solar energy is not available. Hybridization and thermal storage can enhance the economic value of the electricity produced and reduce its average cost. This chapter provides an introduction to the more detailed chapters on each of the three technologies, an overview of the technologies, their current status, and a map identifying the U.S. regions with best solar resource.

Parabolic Trough systems use parabolic trough-shaped mirrors to focus sunlight on thermally efficient receiver tubes that contain a heat transfer fluid (Figure 1). This fluid is heated to 390°C (734°F) and pumped through a series of heat exchangers to produce superheated steam which powers a conventional turbine generator to produce electricity. Nine trough systems, built in the mid to late 1980's, are currently generating 354 MW in Southern California. These systems, sized between 14 and 80 MW, are hybridized with up to 25% natural gas in order to provide dispatchable power when solar energy is not available.

Cost projections for trough technology are higher than those for power towers and dish/engine systems due in large part to the lower solar concentration and hence lower temperatures and efficiency. However, with 10 years of operating experience, continued technology improvements, and O&M cost reductions, troughs are the least expensive, most reliable solar technology for near-term applications.

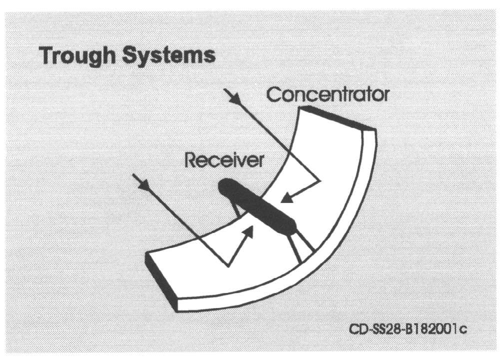

Figure 1. Solar parabolic trough.

Power Tower systems use a circular field array of heliostats (large individually-tracking mirrors) to focus sunlight onto a central receiver mounted on top of a tower (Figure 2). The first power tower, Solar One, which was built in Southern California and operated in the mid-1980's, used a water/steam system to generate 10 MW of power. In 1992, a consortium of U.S. utilities banded together to retrofit Solar One to demonstrate a molten-salt receiver and thermal storage system.

The addition of this thermal storage capability makes power towers unique among solar technologies by promising dispatchable power at load factors of up to 65%. In this system, molten-salt is pumped from a "cold" tank at 288°C

(550°F) and cycled through the receiver where it is heated to 565°C (1,049°F) and returned to a "hot" tank. The hot salt can then be used to generate electricity when needed. Current designs allow storage ranging from 3 to 13 hours.

"Solar Two" first generated power in April 1996, and is scheduled to run for a 3-year test, evaluation, and power production phase to prove the molten-salt technology. The successful completion of Solar Two should facilitate the early commercial deployment of power towers in the 30 to 200 MW range.

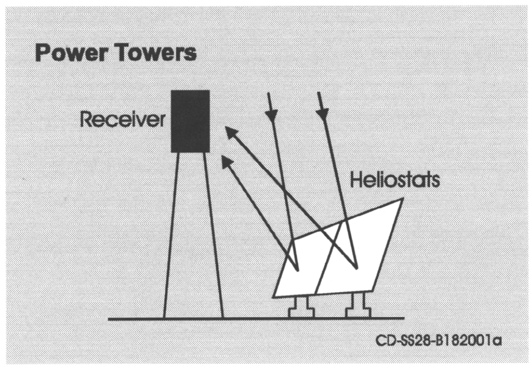

Figure 2. Solar power tower.

Dish/Engine systems use an array of parabolic dish-shaped mirrors (stretched membrane or flat glass facets) to focus solar energy onto a receiver located at the focal point of the dish (Figure 3). Fluid in the receiver is heated to 750°C (1,382°F) and used to generate electricity in a small engine attached to the receiver. Engines currently under consideration include Stirling and Brayton cycle engines. Several prototype dish/engine systems, ranging in size from 7 to 25 kW_e, have been deployed in various locations in the U.S. and abroad.

High optical efficiency and low startup losses make dish/engine systems the most efficient (29.4% record solar to electricity conversion) of all solar technologies. In addition, the modular design of dish/engine systems make them a good match for both remote power needs in the kilowatt range as well as hybrid end-of-the-line grid-connected utility applications in the megawatt range. If field validation of these systems is successful in 1998 and 1999, commercial sales could commence as early as 2000.

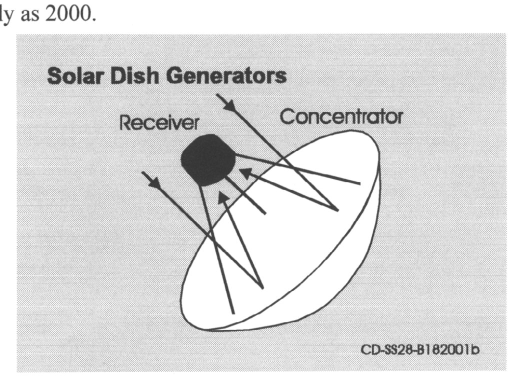

Figure 3. Solar dish/engine system.

OVERVIEW OF SOLAR THERMAL TECHNOLOGIES

Technology Comparison

Table 1 below highlights the key features of the three solar technologies. Towers and troughs are best suited for large, grid-connected power projects in the 30-200 MW size, whereas, dish/engine systems are modular and can be used in single dish applications or grouped in dish farms to create larger multi-megawatt projects. Parabolic trough plants are the most mature solar power technology available today and the technology most likely to be used for near-term deployments. Power towers, with low cost and efficient thermal storage, promise to offer dispatchable, high capacity factor, solar-only power plants in the near future. The modular nature of dishes will allow them to be used in smaller, high-value applications.

Towers and dishes offer the opportunity to achieve higher solar-to-electric efficiencies and lower cost than parabolic trough plants, but uncertainty remains as to whether these technologies can achieve the necessary capital cost reductions and availability improvements. Parabolic troughs are currently a proven technology primarily waiting for an opportunity to be developed. Power towers require the operability and maintainability of the molten-salt technology to be demonstrated and the development of low cost heliostats. Dish/engine systems require the development of at least one commercial engine and the development of a low cost concentrator.

Table 1. Characteristics of solar thermal electric power systems.

	Parabolic Trough	Power Tower	Dish/Engine
Size	30-320 MW*	10-200 MW*	5-25 kW*
Operating Temperature (°C/°F)	390/734	565/1,049	750/1,382
Annual Capacity Factor	23-50%*	20-77%*	25%
Peak Efficiency	20%(d)	23%(p)	29.4%(d)
Net Annual Efficiency	11(d')-16%*	7(d')-20%*	12-25%*(p)
Commercial Status	Commercially Available	Scale-up Demonstration	Prototype Demonstration
Technology Development Risk	Low	Medium	High
Storage Available	Limited	Yes	Battery
Hybrid Designs	Yes	Yes	Yes
Cost			
$/m^2$	630-275*	475-200*	3,100-320*
$/W	4.0-2.7*	4.4-2.5*	12.6-1.3*
$/W_p$ †	4.0-1.3*	2.4-0.9*	12.6-1.1*

* Values indicate changes over the 1997-2030 time frame.

† $/W_p$ removes the effect of thermal storage (or hybridization for dish/engine). See discussion of thermal storage in the power tower TC and footnotes in Table 4.

(p) = predicted; (d) = demonstrated; (d') = has been demonstrated, out years are predicted values

Cost Versus Value

Through the use of thermal storage and hybridization, solar thermal electric technologies can provide a firm and dispatchable source of power. Firm implies that the power source has a high reliability and will be able to produce power when the utility needs it. Dispatchability implies that power production can be shifted to the period when it is needed. As a result, firm dispatchable power is of value to a utility because it offsets the utility's need to build and operate new power plants. This means that even though a solar thermal plant might cost more, it can have a higher value.

OVERVIEW OF SOLAR THERMAL TECHNOLOGIES

Solar Thermal Power Cost and Development Issues

The cost of electricity from solar thermal power systems will depend on a multitude of factors. These factors, discussed in detail in the specific technology sections, include capital and O&M cost, and system performance. However, it is important to note that the technology cost and the eventual cost of electricity generated will be significantly influenced by factors "external" to the technology itself. As an example, for troughs and power towers, small stand-alone projects will be very expensive. In order to reduce the technology costs to compete with current fossil technologies, it will be necessary to scale-up projects to larger plant sizes and to develop solar power parks where multiple projects are built at the same site in a time phased succession. In addition, since these technologies in essence replace conventional fuel with capital equipment, the cost of capital and taxation issues related to capital intensive technologies will have a strong effect on their competitiveness.

Solar Resources

Solar resource is one of the most important factors in determining performance of solar thermal systems. The Southwestern United States potentially offers the best development opportunity for solar thermal electric technologies in the world. There is a strong correlation between electric power demand and the solar resource due largely to the air conditioning loads in the region. Figure 4 shows the direct normal insolation for the United States.

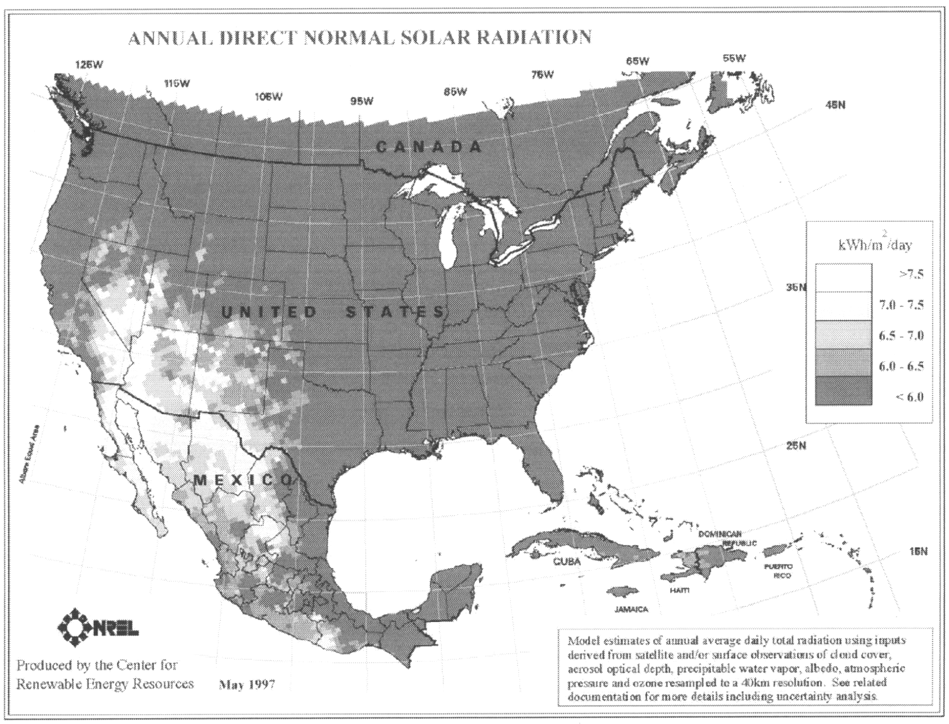

Figure 4. Direct normal insolation resource.

OVERVIEW OF SOLAR THERMAL TECHNOLOGIES

Summary

Solar thermal power technologies are in different stages of development. Trough technology is commercially available today, with 354 MW currently operating in the Mojave Desert in California. Power towers are in the demonstration phase, with the 10 MW Solar Two pilot plant located in Barstow, CA., currently undergoing at least two years of testing and power production. Dish/engine technology has been demonstrated. Several system designs are under engineering development, a 25 kW prototype unit is on display in Golden, CO, and five to eight second-generation systems are scheduled for field validation in 1998. Solar thermal power technologies have distinct features that make them attractive energy options in the expanding renewable energy market worldwide. Comprehensive reviews of the solar thermal electric technologies are offered in References 1 and 2.

References

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SOLAR POWER TOWER

1.0 System Description

Solar power towers generate electric power from sunlight by focusing concentrated solar radiation on a tower-mounted heat exchanger (receiver). The system uses hundreds to thousands of sun-tracking mirrors called heliostats to reflect the incident sunlight onto the receiver. These plants are best suited for utility-scale applications in the 30 to 400 MW_e range.

In a molten-salt solar power tower, liquid salt at 290°C (554°F) is pumped from a 'cold' storage tank through the receiver where it is heated to 565°C (1,049°F) and then on to a 'hot' tank for storage. When power is needed from the plant, hot salt is pumped to a steam generating system that produces superheated steam for a conventional Rankine-cycle turbine/generator system. From the steam generator, the salt is returned to the cold tank where it is stored and eventually reheated in the receiver. Figure 1 is a schematic diagram of the primary flow paths in a molten-salt solar power plant. Determining the optimum storage size to meet power-dispatch requirements is an important part of the system design process. Storage tanks can be designed with sufficient capacity to power a turbine at full output for up to 13 hours.

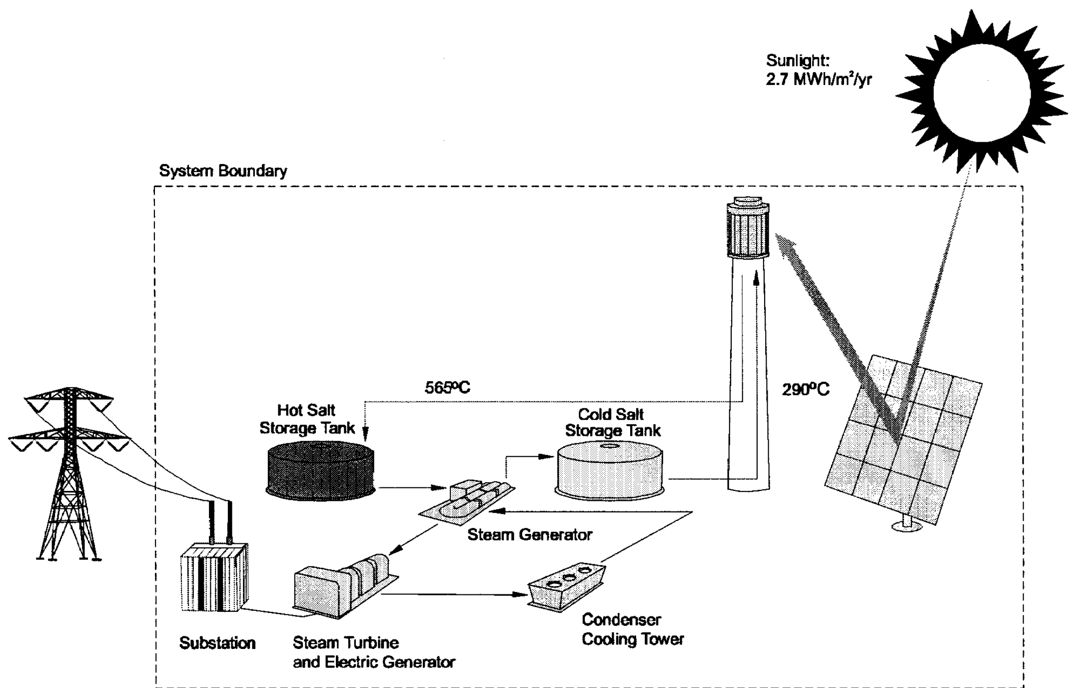

Figure 1. Molten-salt power tower system schematic (Solar Two, baseline configuration).

The heliostat field that surrounds the tower is laid out to optimize the annual performance of the plant. The field and the receiver are also sized depending on the needs of the utility. In a typical installation, solar energy collection occurs at a rate that exceeds the maximum required to provide steam to the turbine. Consequently, the thermal storage system can be *charged* at the same time that the plant is producing power at full capacity. The ratio of the thermal power provided by the collector system (the heliostat field and receiver) to the peak thermal power required by the turbine generator is called the solar multiple. With a solar multiple of approximately 2.7, a molten-salt power tower located in the California Mojave desert can be designed for an annual capacity factor of about 65%. (Based on simulations at Sandia National Laboratories with the SOLERGY [1] computer code.) Consequently, a power tower could potentially operate for 65% of the year without the need for a back-up fuel source. Without energy storage, solar technologies are limited to annual capacity factors near 25%.

The dispatchability of electricity from a molten-salt power tower is illustrated in Figure 2, which shows the load-dispatching capability for a typical day in Southern California. The figure shows solar intensity, energy stored in the hot tank, and electric power output as functions of time of day. In this example, the solar plant begins collecting thermal energy soon after sunrise and stores it in the hot tank, accumulating energy in the tank throughout the day. In response to a peak-load demand on the grid, the turbine is brought on line at 1:00 PM and continues to generate power until 11 PM. Because of the storage, power output from the turbine generator remains constant through fluctuations in solar intensity and until all of the energy stored in the hot tank is depleted. Energy storage and dispatchability are very important for the success of solar power tower technology, and molten salt is believed to be the key to cost effective energy storage.

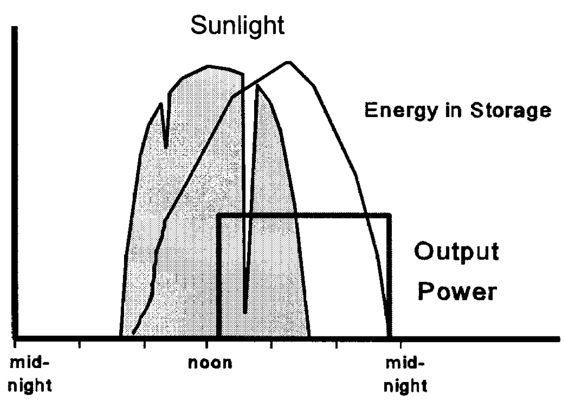

Figure 2. Dispatchability of molten-salt power towers.

Power towers must be large to be economical. Power tower plants are not modular and can not be built in the smaller sizes of dish/Stirling or trough-electric plants and be economically competitive, but they do use a conventional power block and can easily dispatch power when storage is available. In the United States, the Southwest is ideal for power towers because of its abundant high levels of insolation and relatively low land costs. Similar locations in northern Africa, Mexico, South America, the Middle East, and India are also well-suited for power towers.

History

Although power towers are commercially less mature than parabolic trough systems, a number of component and experimental systems have been field tested around the world in the last 15 years, demonstrating the engineering feasibility and economic potential of the technology. Since the early 1980s, power towers have been fielded in Russia, Italy, Spain, Japan, France, and the United States [2]. In Table 1, these experiments are listed along with some of their more important characteristics. These experimental facilities were built to prove that solar power towers can produce electricity and to prove and improve on the individual system components. Solar Two, which is currently going through its startup phase, will generate (in addition to electric power) information on the design, performance, operation and maintenance of molten-salt power towers. The objective of Solar Two is to mitigate the perceived technological and financial risks associated with the first commercial plants and to prove the molten-salt thermal storage technology.

Table 1. Experimental power towers.

Project	Country	Power Output (MWe)	Heat Transfer Fluid	Storage Medium	Operation Began
SSPS	Spain	0.5	Liquid Sodium	Sodium	1981
EURELIOS	Italy	1	Steam	Nitrate Salt/Water	1981
SUNSHINE	Japan	1	Steam	Nitrate Salt/Water	1981
Solar One	USA	10	Steam	Oil/Rock	1982
CESA-1	Spain	1	Steam	Nitrate Salt	1983
MSEE/Cat B	USA	1	Molten Nitrate	Nitrate Salt	1984
THEMIS	France	2.5	Hi-Tec Salt	Hi-Tec Salt	1984
SPP-5	Russia	5	Steam	Water/ Steam	1986
TSA	Spain	1	Air	Ceramic	1993
Solar Two	USA	10	Molten Nitrate Salt	Nitrate Salt	1996

In early power towers, the thermal energy collected at the receiver was used to generate steam directly to drive a turbine generator. Although these systems were simple, they had a number of disadvantages that will be described in the discussions that follow.

Solar One

Solar One, which operated from 1982 to 1988, was the world's largest power tower plant. It proved that large-scale power production with power towers was feasible. In that plant, water was converted to steam in the receiver and used directly to power a conventional Rankine-cycle steam turbine. The heliostat field consisted of 1818 heliostats of 39.3 m^2 reflective area each. The project met most of its technical objectives by demonstrating (1) the feasibility of generating power with a power tower, (2) the ability to generate 10 MW_e for eight hours a day at summer solstice and four hours a day near winter solstice. During its final year of operation, Solar One's availability during hours of sunshine was 96% and its annual efficiency was about 7%. (Annual efficiency was relatively low because of the plant's small size and the inclusion of non-optimized subsystems.)

The Solar One thermal storage system stored heat from solar-produced steam in a tank filled with rocks and sand using oil as the heat-transfer fluid. The system extended the plant's power-generation capability into the night and provided heat for generating low-grade steam for keeping parts of the plant warm during off-hours and for morning startup. Unfortunately, the storage system was complex and thermodynamically inefficient. While Solar One successfully demonstrated power tower technology, it also revealed the disadvantages of a water/steam system, such as the intermittent operation of the turbine due to cloud transcience and lack of effective thermal storage.

During the operation of Solar One, research began on the more advanced molten-salt power tower design described previously. This development culminated in the Solar Two project.

SOLAR POWER TOWER

Solar Two

To encourage the development of molten-salt power towers, a consortium of utilities led by Southern California Edison joined with the U.S. Department of Energy to redesign the Solar One plant to include a molten-salt heat-transfer system. The goals of the redesigned plant, called Solar Two, are to validate nitrate salt technology, to reduce the technical and economic risk of power towers, and to stimulate the commercialization of power tower technology. Solar Two has produced 10 MW of electricity with enough thermal storage to continue to operate the turbine at full capacity for three hours after the sun has set. Long-term reliability is next to be proven.

The conversion of Solar One to Solar Two required a new molten-salt heat transfer system (including the receiver, thermal storage, piping, and a steam generator) and a new control system. The Solar One heliostat field, the tower, and the turbine/generator required only minimal modifications. Solar Two was first attached to a utility grid in early 1996 and is scheduled to complete its startup phase in late 1997.

The Solar Two receiver was designed and built by Boeing's Rocketdyne division. It comprises a series of panels (each made of 32 thin-walled, stainless steel tubes) through which the molten salt flows in a serpentine path. The panels form a cylindrical shell surrounding piping, structural supports, and control equipment. The external surfaces of the tubes are coated with a black Pyromark™ paint that is robust, resistant to high temperatures and thermal cycling, and absorbs 95% of the incident sunlight. The receiver design has been optimized to absorb a maximum amount of solar energy while reducing the heat losses due to convection and radiation. The design, which includes laser-welding, sophisticated tube-nozzle-header connections, a tube clip design that facilitates tube expansion and contraction, and non-contact flux measurement devices, allows the receiver to rapidly change temperature without being damaged. For example, during a cloud passage, the receiver can safely change from 290 to 570°C (554 to 1,058°F) in less than one minute.

The salt storage medium is a mixture of 60 percent sodium nitrate and 40 percent potassium nitrate. It melts at 220°C (428°F) and is maintained in a molten state (290°C/554°F) in the 'cold' storage tank. Molten salt can be difficult to handle because it has a low viscosity (similar to water) and it wets metal surfaces extremely well. Consequently, it can be difficult to contain and transport. An important consideration in successfully implementing this technology is the identification of pumps, valves, valve packing, and gasket materials that will work with molten salt. Accordingly, Solar Two is designed with a minimum number of gasketed flanges and most instrument transducers, valves, and fittings are welded in place.

The energy storage system for Solar Two consists of two 875,000 liter storage tanks which were fabricated on-site by Pitt-Des Moines. The tanks are externally insulated and constructed of stainless steel and carbon steel for the hot and cold tanks, respectively. Thermal capacity of the system is 110 MWh_t. A natural convection cooling system is used in the foundation of each tank to minimize overheating and excessive dehydration of the underlying soil.

All pipes, valves, and vessels for hot salt were constructed from stainless steel because of its corrosion resistance in the molten-salt environment. The cold-salt system is made from mild carbon steel. The steam generator system (SGS) heat exchangers, which were constructed by ABB Lummus, consist of a shell-and-tube superheater, a kettle boiler, and a shell-and-tube preheater. Stainless steel cantilever pumps transport salt from the hot-tank-pump sump through the SGS to the cold tank. Salt in the cold tank is pumped with multi-stage centrifugal pumps up the tower to the receiver.

Solar Two is expected to begin routine daily power production in late 1997. Initial data collected at the plant show that the molten-salt receiver and thermal storage tanks should perform as predicted during design. For example, data collected on March 26, 1997, revealed that the receiver absorbed 39.8 MW_t, which is 93% of the design value. Considering the fact that the heliostat field had significant alignment problems at the time of the measurement, the receiver is expected to reach 100% of the design after realignment. This was reaffirmed by efficiency tests conducted in October 1997 which indicated an 87% value; this is nearly identical to the design prediction. The hot tank within the thermal storage system has also exhibited excellent thermal characteristics. Figure 3 depicts a month-long cool down of the hot storage tank when it was filled with molten salt. It can be seen that the tank cools very slowly (about 75°C/167°F over one month) and the measured thermal losses are within about 10% of the design prediction.

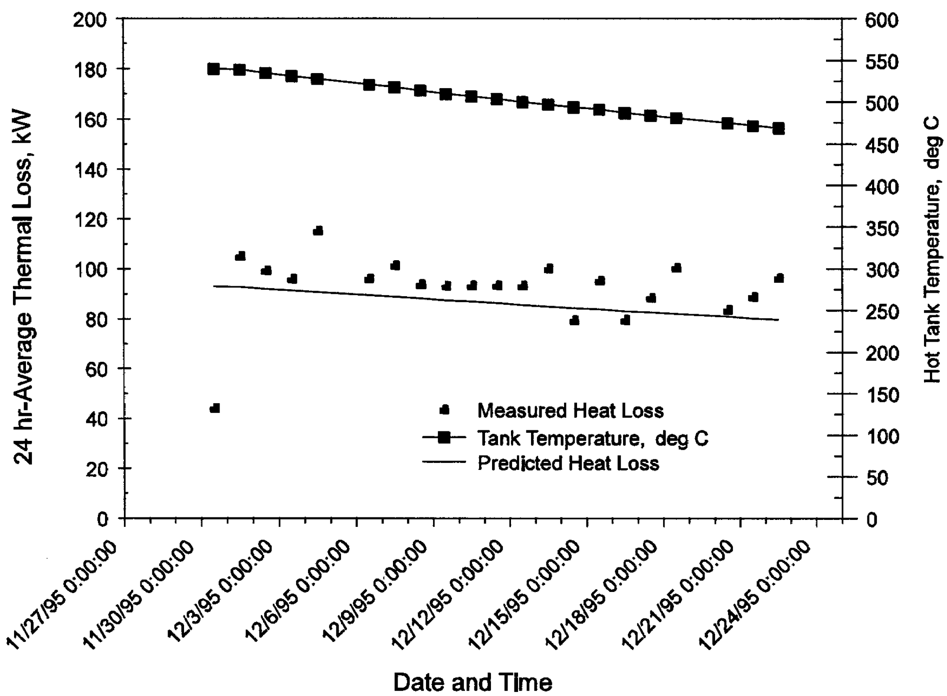

Figure 3. Cool down of hot storage tank at Solar Two.

It is important to note that at 10 MW, Solar Two is too small to be economically viable. Operation and maintenance (O&M) costs for a small solar only power tower are too high. This can be demonstrated by examing Table 3 (to be presented later). O&M costs become reasonable at 30 MW or greater system sizes. This has also been observed at the operating SEGS trough plants.

SOLAR POWER TOWER

2.0 System Application, Benefits, and Impacts

Overview

To date, the largest power towers ever built are the 10 MW Solar One and Solar Two plants. Assuming success of the Solar Two project, the next plants could be scaled-up to between 30 and 100 MW in size for utility grid connected applications in the Southwestern United States and/or international power markets. New peaking and intermediate power sources are needed today in many areas of the developing world. India, Egypt, and South Africa are locations that appear to be ideally suited for power tower development. As the technology matures, plants with up to a 400 MW rating appear feasible. As non-polluting energy sources become more favored, molten-salt power towers will have a high value because the thermal energy storage allows the plant to be dispatchable. Consequently, the value of power is worth more because a power tower plant can deliver energy during peak load times when it is more valuable. Energy storage also allows power tower plants to be designed and built with a range of annual capacity factors (20 to 65%). Combining high capacity factors and the fact that energy storage will allow power to be brought onto the grid in a controlled manner (i.e., by reducing electrical transients thus increasing the stability of the overall utility grid), total market penetration should be much higher than an intermittent solar technology without storage.

One possible concern with the technology is the relatively high amount of land and water usage. This may become an important issue from a practical and environmental viewpoint since these plants are typically deployed within desert areas that often lack water and have fragile landscapes. Water usage at power towers is comparable to other Rankine cycle power technologies of similar size and annual performance. Land usage, although significant, is typically much less than that required for hydro [3] and is generally less than that required for fossil (e.g., oil, coal, natural gas), when the mining and exploration of land are included.

Initial System Application - Hybrid Plants

To reduce the financial risk associated with the deployment of a new power plant technology and to lower the cost of delivering solar power, initial commercial-scale (>30 MW_e) power towers will likely be hybridized with conventional fossil-fired plants. Many hybridization options are possible with natural gas combined-cycle and coal-fired or oil-fired Rankine plants. One opportunity for hybrid integration with a combined cycle is depicted in Figure 4.

In a hybrid plant, the solar energy can be used to reduce fossil fuel usage and/or boost the power output to the steam turbine. Typical daily power output from the hypothetical "power boost" hybrid power plant is depicted in Figure 5. From the figure it can be seen that in a power boost hybrid plant we have, in effect, "piggybacked" a solar-only plant on top of a base-loaded fossil-fueled plant.

In the power boost hybrid plant, additional electricity is produced by over sizing the steam turbine, contained within a coal-fired Rankine plant or the bottoming portion of a combined-cycle plant (Figure 4), so that it can operate on both full fossil and solar energy when solar is available. Studies of this concept have typically oversized the steam turbine from 25% to 50% beyond what the turbine can produce in the fossil-only mode. Oversizing beyond this range is not recommended because the thermal-to-electric conversion efficiency will degrade at the part loads associated with operating in the fuel-only mode.

SOLAR POWER TOWER

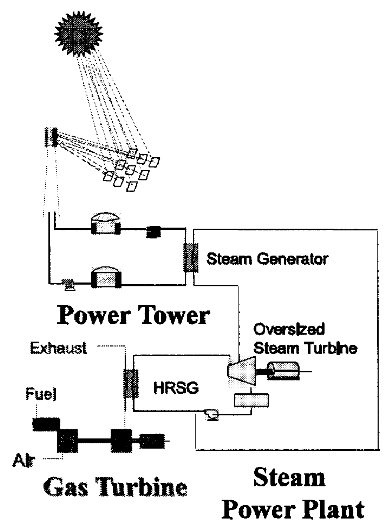

Figure 4. Power tower hybridized with combined cycle plant [4]. Power is produced in the gas turbine (fossil only) and from the steam turbine (fossil and solar). Steam from the solar steam generator is blended with fossil steam from the heat recovery steam generator (HRSG) before entering a steam turbine.

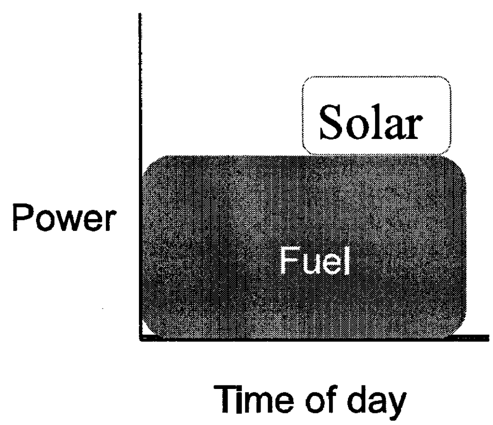

Figure 5. A hypothetical power profile from a hybrid plant. In this case, thermal storage is used to dispatch the solar electricity late in the day to meet an evening peak that lasts well into the night (a pattern that is common in the U.S. Southwest and in many developing nations).

SOLAR POWER TOWER

When hybridizing a solar power tower with a base-load fossil-fired plant, solar contributes about 25% of the peak power output from the plant and between 10 and 25% of the annual electricity. (The higher annual solar fraction can be achieved with 13 hours of thermal storage and the lower solar fraction with just a few hours of storage.) Designing plants with a relatively modest solar fraction reduces financial risk because the majority of the electricity is derived from proven fossil technology and steady payment for power sales is assured.

System Benefits -Energy Storage

The availability of an inexpensive and efficient energy storage system may give power towers a competitive advantage. Table 2 provides a comparison of the predicted cost, performance, and lifetime of solar-energy storage technologies for hypothetical 200 MW plants [5,6].

Table 2. Comparison of solar-energy storage systems.

	Installed cost of energy storage for a 200 MW plant ($/kWhr$_e$)	Lifetime of storage system (years)	Round-trip storage efficiency (%)	Maximum operating temperature (°C/°F)
Molten-Salt Power Tower	30	30	99	567/1,053
Synthetic-Oil Parabolic Trough	200	30	95	390/734
Battery Storage Grid Connected	500 to 800	5 to 10	76	N/A

Thermal-energy storage in the power tower allows electricity to be dispatched to the grid when demand for power is the highest, thus increasing the monetary value of the electricity. Much like hydro plants, power towers with salt storage are considered to be a dispatchable rather than an intermittent renewable energy power plant. For example, Southern California Edison company gives a power plant a capacity payment if it is able to meet their dispatchability requirement: an 80% capacity factor from noon to 6 PM, Monday through Friday, from June through September. Detailed studies [7] have indicated that a solar-only plant with 4 hours of thermal storage can meet this dispatchability requirement and thus qualify for a full capacity payment. While the future deregulated market place may recognize this value differently, energy delivered during peak periods will certainly be more valuable.

Besides making the power dispatchable, thermal storage also gives the power-plant designer freedom to develop power plants with a wide range of capacity factors to meet the needs of the utility grid. By varying the size of the solar field, solar receiver, and size of the thermal storage, plants can be designed with annual capacity factors ranging between 20 and 65% (see Figure 6).

Economic studies have shown that levelized energy costs are reduced by adding more storage up to a limit of about 13 hours (~65% capacity factor) [8]. While it is true that storage increases the cost of the plant, it is also true that plants with higher capacity factors have better economic utilization of the turbine, and other balance of plant equipment. Since salt storage is inexpensive, reductions in LEC due to increased utilization of the turbine more than compensates for the increased cost due to the addition of storage.

SOLAR POWER TOWER

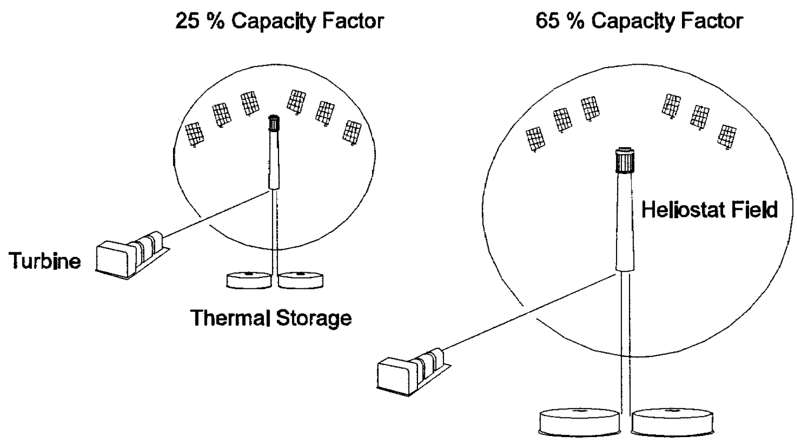

Figure 6. In a solar power tower, plant design can be altered to achieve different capacity factors. To increase capacity factor for a given turbine size, the designer would (1) increase the number of heliostats, (2) enlarge the thermal storage tanks, (3) raise the tower, and (4) increase the receiver dimensions.

Environmental Impacts

No hazardous gaseous or liquid emissions are released during operation of the solar power tower plant. If a salt spill occurs, the salt will freeze before significant contamination of the soil occurs. Salt is picked up with a shovel and can be recycled if necessary. If the power tower is hybridized with a conventional fossil plant, emissions will be released from the non-solar portion of the plant.

3.0 Technology Assumptions and Issues

Assuming success at Solar Two, power tower technology will be on the verge of technology readiness for commercial applications. However, progress related to scale-up and R&D for specific subsystems is still needed to reduce costs and to increase reliability to the point where the technology becomes an attractive financial investment. Promising work is ongoing in the following areas:

First Commercial System

Ideally, to be economically competitive with conventional fossil technology, a power tower should be at least 10 times larger than Solar Two [4]. It may be possible to construct this plant directly following Solar Two, but the risk perceived by the technical and financial communities may require that a plant of intermediate size (30-50 MW) be constructed first. The World Bank will consider requests for funding power tower projects following a successful two-year operation of Solar Two. However, countries interested in the technology have indicated they may need to see a utility-scale plant operating in the U.S. before they will include power towers in their energy portfolio. Since the electricity cost of a stand-alone 30 MW solar-only plant will be significantly higher than the fossil competition, innovative financing options or subsidies need to be developed to support this mid-size project. Fossil hybridization designs are also being explored as another possible way of aiding market entry (see hybrid discussion in Section 2). The benefits of the reduced size plant include reduced scale-up risk and reduced capital investment.

Heliostats

Relatively few heliostats have been manufactured to date, and their cost is high (>$250/m^2). As the demand for solar power increases, heliostat mass production methods will be developed that will significantly reduce their cost (actual evidence of this has been seen in the parabolic trough industry). Research is currently being conducted under the Solar Manufacturing Technology (SolMaT) Initiative to develop low-cost manufacturing techniques for early commercial low volume builds. Prices are a strong function of annual production rate, as shown in Figure 7. They were estimated by U.S. heliostat manufacturers for rates ≤ 2,500/yr [9-11]. The price for high annual production (50,000/yr) is a rough estimate. It was obtained by assuming that the price of the entire heliostat scaled with the price of the drive system. Prices for heliostat drives at production levels from 1 to 50,000 units per year were provided by a U.S. drive manufacturer [12,13]. (50,000 units corresponds to 1 GW of additional capacity per year.)

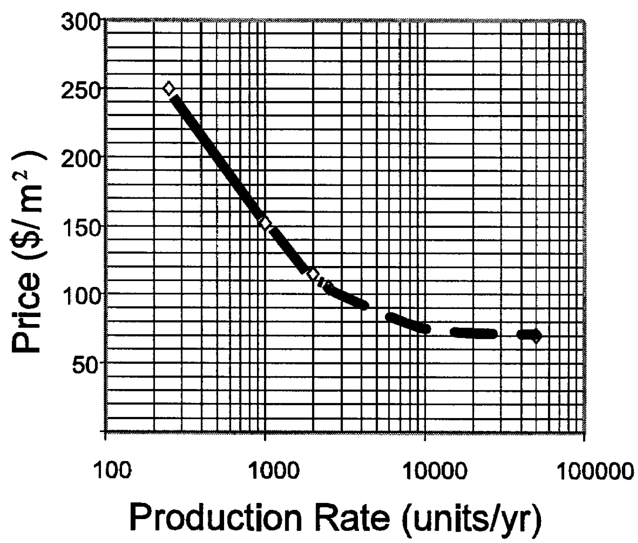

Figure 7. Heliostat price as a function of annual production volume. These prices apply to a heliostat with a surface area of 150 m^2 and similar in design to those tested at Sandia National Laboratories.

Since the heliostat field represents the largest single capital investment in a power tower plant, advancements in technology are needed to improve the ability to manufacture, reduce costs, and increase the service life of heliostats. In particular, a lower cost azimuth drive system is needed (i.e., to rotate the heliostat around an axis that is perpendicular to the ground).

Receiver

Smaller, simpler receivers are needed to improve efficiency and reduce maintenance. Advanced receiver development currently underway, under the SolMaT Initiative, includes consideration of new steel alloys for the receiver tubes and ease of manufacture for the entire receiver subsystem. Panels of these new receiver designs are being tested at Solar Two.

Molten Salt

Molten nitrate salt, though an excellent thermal storage medium, can be a troublesome fluid to deal with because of its relatively high freezing point (220°C/428°F). To keep the salt molten, a fairly complex heat trace system must be employed. (Heat tracing is composed of electric wires attached to the outside surface of pipes. Pipes are kept warm by way of resistance heating.) Problems were experienced during the startup of Solar Two due to the improper installation of the heat trace. Though this problem has been addressed and corrected, research is needed to reduce the reliance on heat tracing in the plant. This could be accomplished by one or more of the following options: (1) develop a salt "anti-freeze" to lower the freezing point, (2) identify and/or develop components that can be "cold started" without preapplication of the heat trace, or (3) develop thermal management practices that are less reliant on heat trace. Within the Solar Two project, the third option will be explored. If it is unsuccessful, the other two options should be pursued. Also, valves can be troublesome in molten-salt service. Special packings must be used, oftentimes with extended bonnets, and leaks are not uncommon. Furthermore, freezing in the valve or packing can prevent it from operating correctly. While today's valve technology is adequate for molten-salt power towers, design improvements and standardization would reduce risk and ultimately reduce O&M costs.

Steam Generator

The steam generator design selected for the Solar Two project is completely different than the prototype tested at Sandia Laboratories during the technology development activity of the 1980's. The recirculating-drum-type system tested at Sandia performed well. However, at Solar Two, a kettle-boiler design was selected in an attempt to reduce cost. Significant problems have been encountered with this new system during the startup phase at Solar Two, requiring a redesign in many areas. Depending on the success of implementing the design changes, it may be appropriate to re-evaluate the optimum steam generator design before proceeding to the first commercial plant.

4.0 Performance and Cost

Table 3 summarizes the performance and cost indicators for the solar power tower system being characterized in this report.

4.1 Evolution Overview

1997 Technology: The 1997 baseline technology is the Solar Two project with a 43 MW_t molten nitrate salt central receiver with three hours of thermal storage and 81,000 m^2 of heliostats. The solar input is converted in the existing 10 MW net Rankine steam cycle power plant. The plant is described in detail in Section 1.0 and is expected to have a 20% annual capacity factor following its start-up period.

Table 3. Performance and cost indicators.

INDICATOR NAME	UNITS	Solar Two Prototype 1997	+/-%	Small Hybrid Booster 2000	+/-%	Large Hybrid Booster 2005	+/-%	Solar Only 2010	+/-%	Advanced Solar Only 2020	+/-%	Advanced Solar Only 2030	+/-%
Plant Size	MW	10		30		100		200		200		200	
Receiver Thermal Rating	MW_t	43		145		470		1,400		1,400		1,400	
Heliostat Size	m^2	40		95		150		150		150		150	
Solar Field Area	m^2	81,000		275,000		883,000		2,477,000		2,477,000		2,477,000	
Thermal Storage	Hours	3		7		6		13		13		13	
	MWh_t	114		550		1,600		6,760		6,760		6,760	
Performance													
Capacity Factor	%	20		43		44		65		77		77	
Solar Fraction		1.00		0.22		0.22		1.00		1.00		1.00	
Direct Normal Insolation	$kWh/m^2/yr$	2,700		2,700		2,700		2,700		2,700		2,700	
Annual Solar to Elec. Eff.	%	8.5	+5/-20*	15.0	+5/-20	16.2	+5/-20	17.0	+5/-20	20.0	+5/-20	20.0	+5/-20
Annual Energy Production	GWh/yr	17.5		113.0		385.4		1,138.8		1,349.0		1,349.0	
Capital Cost													
Structures & Improvements	$\$/kW_{nameplate}$	†		116	15	60	15	50	15	50	15	50	15
Heliostat System		†		1,666	25	870	25	930	25	865	25	865	25
Tower/Receiver System				600	25	260	25	250	25	250	25	250	25
Thermal Storage System		370		420	15	240	15	300	15	300	15	300	15
Steam Gen System		276		177	15	110	15	85	15	85	15	85	15
EPGS/Balance of Plant		†		417	15	270	15	400	15	400	15	400	15
Master Control System		†		33	15	10	15	15	15	15	15	15	15
Directs SubTotal (A)				3,429		1,820		2,030		1,965		1,965	
Indirect Engineering/Other	A * 0.1			343		182		203		197		197	
SubTotal (B)				3,772		2,002		2,233		2,162		2,162	
Project/Process Contingency	B * 0.15			566		300		335		325		325	
Total Plant Cost‡				4,338		2,302		2,568		2,487		2,487	
Land (@ $4,942/hectare)				27		27		37		37		37	
Total Capital Requirements	$\$/kW_{nameplate}$			4,365		2,329		2,605		2,523		2,523	
	$\$/kW_{peak}$ #			2,425		1,294		965		934		934	
	$\$/m^2$			476		264		210		204		204	
Operation and Maintenance Cost													
Fixed Labor & Materials	$/kW-yr												
Total O&M Costs		300		67	25	23	25	30	25	25	25	25	25

Notes:

1. The columns for "+/-%" refer to the uncertainty associated with a given estimate.
2. The construction period is assumed to be 2 years.

* Design specification for Solar Two. This efficiency is predicted for a mature operating year.

† Cost of these items at Solar Two are not characteristic of a commercial plant and have, therefore, not been listed.

‡ Total plant cost for Solar Two are the actuals incurred to convert the plant from Solar One to Solar Two. The indirect factors listed do not apply to Solar Two.

\# To convert to peak values, the effect of thermal storage must be removed. A first-order estimate can be obtained by dividing installed costs by the solar multiple (i.e., SM = {peak collected solar thermal power} ÷ {power block thermal power}). For example, as discussed in the text, in 2010 the peak receiver absorbed power is 1400 MW_t. If this is attached to a 220 MW_e turbine (gross) with a gross efficiency of 42%, thermal demand of the turbine is 520 MW_t. Thus, SM is 2.7 (i.e., 1400/520) and peak installed cost is 2605/2.7 = $\$965/kW_{peak}$. Solar multiples for years 1997, 2000, and 2005 are 1.2, 1.8, and 1.8, respectively.

SOLAR POWER TOWER

2000 Technology: The first commercial scale power tower project following the Solar Two project is assumed to be a 145 MW_t molten nitrate salt central receiver with seven hours of thermal storage and 275,000 m^2 of heliostats. The solar plant may be integrated with either a 30 MW_e solar-only Rankine cycle plant or with a combined cycle hybrid system like the power booster system described in Section 2.0. A hybrid plant with a 30 MW_e solar-power-boost, and a 43% annual capacity factor from solar input, is assumed in the case study presented here.

2005 Technology: The system is scaled-up to the original Utility Study [14] size: a 470 MW_t receiver and 883,000 m^2 heliostat field. Again, the solar plant could be integrated into a 100 MW_e solar-only Rankine power plant or a hybrid combined cycle power-boost system. A hybrid plant with a 100 MW_e solar-power-boost, and a 44% annual capacity factor from solar input, is assumed in the case study presented here.

2010 Technology: In 2010, solar-only nitrate-salt power tower plants are assumed to be competitive. The receiver is scaled up to 1,400 MW_t with thirteen hours of thermal storage and 2,477,000 m^2 of heliostats. The solar plant is attached to a 200 MW Rankine cycle steam turbine and would achieve an annual capacity factor of about 65%.

2020 Technology: The 2020 technology continues to be a 200 MW Rankine solar-only nitrate-salt power plant. Technology development, manufacturing advances, and increased production volumes are assumed to reduce solar plant cost to mature cost targets. Minor technology advances are assumed to continue to fine-tune overall plant performance.

4.2 Performance and Cost Discussion

All annual energy estimates presented in Table 3 are based on simulations with the SOLERGY computer code [1]. The inputs to the SOLERGY computer code (mirror reflectance, receiver efficiency, startup times, parasitic power, plant availability, etc.) are based on measured data taken from the 10 MW_e Solar One and the small (~1 MW_e) molten-salt receiver system test conducted in the late 1980's [15,16]. The SOLERGY code itself has been validated with a full year of operation at Solar One [17]. However, no overall annual energy data is available from an operating molten-salt power tower. Collection of this data is one of the main goals of the Solar Two demonstration project.

The costs presented in Table 3 for Solar Two are the actuals incurred for the project as reported by Southern California Edison. Capital and operation and maintenance (O&M) cost estimates for 2000 and beyond are consistent with estimates contained in the U.S. Utility Study [14] and the International Energy Agency studies [16]. These studies have been used as a basis to estimate costs for hybrid options and plants with different capacity factors [4]. In addition, O&M costs for power-tower plants with sizes $\leq$ 100 MW_e have been compared with actuals incurred at the operating 10 to 80 MW_e solar-trough plants in California with similar sizes to insure consistency. Because of the many similarities between trough and tower technology, a first-order assumption that O&M costs at trough and tower plants are similar has been made.

1997 Technology: During 1997, the plant was completing its startup phase. Solar Two is a sub-commercial-scale plant that is designed to demonstrate the essential elements of the technology. To save capital costs, the plant was sized to have a 20% capacity factor and three hours of thermal storage.

SOLAR POWER TOWER

The solar-to-electric annual efficiency at Solar Two will be significantly lower than initial commercial-scale plants (8.5% vs. 15% in Table 3) because:

- Unlike the commercial plant, Solar Two does not use a reheat turbine cycle. Consequently, gross Rankine-cycle efficiency will be revised from 42% to 33%;

- Some of the Rankine-cycle equipment is old and other sections of the plant do not employ the equipment redundancy that is expected in the commercial plant. Plant availability is thus expected to be lowered from 91% to 88%;

- The Solar Two heliostat field is not state-of-the-art. The heliostats being used employ an old control strategy and the mirrors have experienced degradation due to corrosion. Also, the reflectance of these older mirrors is below today's standard (89% vs. 94%). Reflectance, corrosion, and controls are not problems with current heliostat technology. In addition, the 108 new heliostats added to the field, though inexpensive, are too large for the receiver that is installed. Consequently, the reflected beams from these heliostats are too large and a portion of the beams do not intercept the receiver target. Combining all these effects, a field performance degradation factor of about 0.9 relative to the commercial plant is expected; and

- Since Solar Two is only 10 MW with a 20% capacity factor, parasitic electricity use will be a much greater fraction of the total gross generation than for a commercial plant with a much higher capacity factor (e.g. parasitics consumed when the plant is offline will be a much greater fraction of the total when the plant has a 20% rather than a 60% capacity factor.) Parasitic energy use at Solar Two is expected to be about 25% of the total gross generation; for a commercial plant, parasitics are predicted to be about 10%.

Combining the factors discussed above, the simple equation below shows how the 15% annual efficiency for the commercial plant is equivalent to about 8.5% at Solar Two.

$$8.5\% = 15\% * (0.33/0.42) * (0.88/0.91) * (0.9) * (0.75/0.9)$$

The 8.5% efficiency is expected to be achieved at Solar Two during its last year of operation after startup problems with the new technology have been solved.

2000 Technology: Following successful operation of Solar Two, the first commercial scale power tower is assumed to be built in the Southwestern U.S. or within a developing nation. At the present time, the Solar Two business consortium is comfortable with scaling up the Solar Two receiver to 145 MW_t (3.3 times larger than Solar Two [18]). This larger receiver will be combined with a state-of-the-art glass heliostat field ($\geq$ 95 m^2 each) [19], a next-generation molten-salt steam generator design (based on lessons learned at Solar Two), a high-efficiency steam turbine cycle, and will employ modern balance of plant equipment that will improve plant availability. As pointed out in the previous paragraph, these improvements are expected to increase annual efficiency from 8.5 to 15%.

To reduce the financial risk associated with the deployment of this first commercial-scale plant and to lower the cost of delivering solar power, the plant will likely be hybridized with a base-loaded fossil-fired plant. If the solar plant is interfaced with a combined cycle plant, the system layout could be similar to that depicted in Figure 4. Hybridization significantly reduces the cost of producing solar power relative to a solar-only design for the following reasons:

- Capital costs for the solar turbine are reduced because only an increment to the base-load fossil turbine must be purchased;
- O&M costs are reduced because only an increment beyond the base-load O&M staff and materials must be used to maintain the solar-specific part of the plant; and,
- The solar plant produces more electricity because the turbine is hot all the time and daily startup losses incurred in a solar-only plant are avoided.

A 145 MW_t receiver that is interfaced with a 30 MW_e turbine-generator increment to a 105 MW_e base-loaded fossil plant would yield approximately a 43% annual solar capacity factor, based on SOLERGY simulations. This plant would have about 7 hours of storage (550 MWh_t, or 5 times larger than Solar Two) and would be capable of dispatching power to meet a late afternoon or early evening peak power demand that is typically seen on utility-power grids (see Figure 5).

2005 Technology: The receiver in this plant is scaled-up another factor of 3.3 to 470 MW_t. The receiver materials will likely be improved relative to the 316 stainless steel tubes currently used at Solar Two. Stainless is limited to a peak incident flux of about 800 suns. SunLab and Rocketdyne are currently testing advanced receiver materials that appear capable of withstanding greater than 1100 suns. This higher-concentration receiver will be able to absorb a given amount of solar energy with a smaller surface area. Reducing surface area improves efficiency because thermal losses are lowered. In addition, advanced manufacturing techniques currently being developed in a Sandia/Boeing research project (e.g. pulled tube-to-header connections) will be employed to reduce the cost of the receiver and improve reliability.

Large-area heliostats (150 m^2), similar to those successfully tested at Sandia National Laboratories [19], are expected to be used. The improved economy of scale will significantly reduce the cost of the heliostats on a $\$/m^2$ basis. In addition, increases in annual production are expected to lower heliostat costs.

A hybrid plant is again proposed to help mitigate the scale-up risk and to reduce the cost of producing solar power. System configuration could be similar to Figure 4.

A 470 MW_t receiver that is interfaced with a 100 MW_e turbine-generator increment to a 350 MW_e base-loaded fossil plant would yield approximately a 44% annual solar capacity factor, based on SOLERGY simulations. This plant would have about 6 hours of storage (1,600 MWh_t) and would be capable of dispatching power to meet a late afternoon or early evening peak power demand.

2010 Technology: In 2010, the first commercial-scale solar-only plants are assumed to be built. Scoping calculations at Sandia National Laboratories suggest that it is feasible to scale-up the receiver another factor of three to a rating of about 1,400 MW_t. If this receiver is attached to a 200 MW steam generation/turbine system, 13 hours of thermal storage (6,760 MWh_t) would be necessary to avoid overfill of the storage and a significant discard of solar energy. The annual capacity factor of this plant would be approximately 65%, and it would run at full turbine output nearly 24 hours/day during the summer months when the daylight hours are longer. During the winter, when days are shorter, the plant would shut down during several hours per night. Alternatively, the turbine could run at part load to maintain the turbine on line. This plant is approaching base-load operation. The same 1,400 MW_t receiver/6,760 MWh_t storage system could also be attached to a 400 MW steam turbine. In this case, the annual capacity factor would be about 33% and the electricity would be dispatched to meet the peaking demands of the grid. However, in this technical characterization, the power tower plant is assumed to be attached to a 200 MW_e turbine.

SOLAR POWER TOWER

2020 Technology: Power plant size is assumed to remain at 200 MW_e. Power towers built between the years 2010 and 2020 should have a receiver that has a significantly higher efficiency than is currently possible with today's technology. Receivers within current power towers are coated with a highly absorptive black paint. However, the emissivity of the paint is also high which leads to a relatively large radiation loss. Future power tower receivers will be coated with a selective surface with a very low emissivity that will significantly reduce radiation losses. Selective surfaces similar to what is needed are currently used in solar parabolic trough receivers. Additional research is needed to produce a surface that won't degrade at the higher operating temperature of the tower (i.e., 650°C/1,202°F vs. 400°C/752°F). Given this improvement, scoping calculations at Sandia indicate that annual receiver efficiency should be improved to about 90%.

By 2020, further improvements in heliostat manufacturing techniques, along with significant increases in annual production, are expected to lower heliostat costs to their final mature value (~$70/$m^2$, see Figure 7). The reflectance of the mirrors is also expected to be improved from the current value of 94% to a value of at least 97%. Advanced reflective materials are currently being investigated in the laboratory.

As the technology reaches maturity, plant parasitics will be fully optimized and plant availability will also improve. Combining all the effects described above, annual plant efficiency is expected to be raised to 20% and annual capacity factor should be raised above 75%.

2030 Technology: No significant improvements in molten nitrate salt power tower technology are assumed beyond 2020. In order for significant improvements to continue, a radical change in power tower technology must take place. Ideas under consideration are an advanced receiver that is capable of efficiently heating air to gas-turbine temperatures (>1,400°C/2,552°F) and pressures (>1,500 kPa) in conjunction with a high-temperature phase-change thermal storage system. If this can be achieved, large solar-only plants with a combined-cycle power block efficiency of 60% or more might be achieved. In addition, as receiver temperatures exceed 1000°C (1,832°F), thermal-chemical approaches to hydrogen generation could be exploited using solar power towers. Since these ideas are in such an early stage, no defendable cost and performance projections can be made at this time.

5.0 Land, Water, and Critical Materials Requirements

The land and water use values provided in Table 4 apply to the solar portion of the power plant. Land use in 1997 is taken from Solar Two design documents. Land use for years 2000 and beyond is based on systems studies [14,16]. The proper way to express land use for systems with storage is ha/MWhr/yr. Expressing land use in units of ha/MW is meaningless to a solar plant with energy storage because the effect of plant capacity factor is lost.

Water use measured at the SEGS VI and VII [20] trough plants form the basis of these estimates. Wet cooling towers are assumed. Water usage at Solar Two should be somewhat higher than at SEGS VI and VII due to a lower power block efficiency at Solar Two (33% gross). However, starting in the year 2000, water usage in a commercial power tower plant, with a high efficiency power block (42% gross), should be about 20% less than SEGS VI and VII. If adequate water is not available at the power plant site, a dry condenser-cooling system could possibly be used. Dry cooling can reduce water needs by as much as 90%. However, if dry cooling is employed, cost and performance penalties are expected to raise levelized-energy costs by at least 10%.

SOLAR POWER TOWER

Table 4. Resource requirements.

Indicator Name	Units	Base Year 1997	2000	2005	2010	2020	2030
Land	ha/MWh/yr	2.7×10^{-3}	1.5×10^{-3}	1.4×10^{-3}	1.3×10^{-3}	1.1×10^{-3}	1.1×10^{-3}
Water	m^3/MWh	3.2	2.4	2.4	2.4	2.4	2.4

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SOLAR PARABOLIC TROUGH

1.0 System Description

Parabolic trough technology is currently the most proven solar thermal electric technology. This is primarily due to nine large commercial-scale solar power plants, the first of which has been operating in the California Mojave Desert since 1984. These plants, which continue to operate on a daily basis, range in size from 14 to 80 MW and represent a total of 354 MW of installed electric generating capacity. Large fields of parabolic trough collectors supply the thermal energy used to produce steam for a Rankine steam turbine/generator cycle.

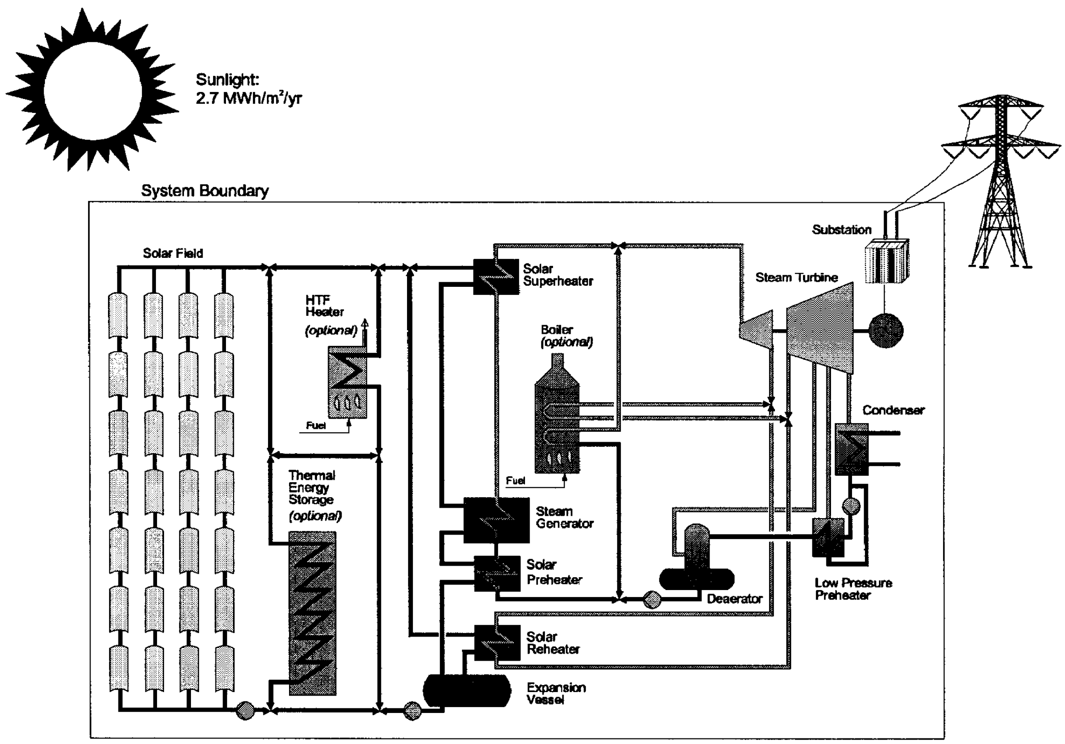

Figure 1. Solar/Rankine parabolic trough system schematic [1].

Plant Overview

Figure 1 shows a process flow diagram that is representative of the majority of parabolic trough solar power plants in operation today. The collector field consists of a large field of single-axis tracking parabolic trough solar collectors. The solar field is modular in nature and is composed of many parallel rows of solar collectors aligned on a north-south horizontal axis. Each solar collector has a linear parabolic-shaped reflector that focuses the sun's direct beam radiation on a linear receiver located at the focus of the parabola. The collectors track the sun from east to west during the day to ensure that the sun is continuously focused on the linear receiver. A heat transfer fluid (HTF) is heated as it circulates through the receiver and returns to a series of heat exchangers in the power block where the fluid is used to generate high-pressure superheated steam. The superheated steam is then fed to a conventional reheat steam turbine/generator to produce electricity. The spent steam from the turbine is condensed in a standard condenser and returned to the heat exchangers via condensate and feedwater pumps to be transformed back into steam. Condenser cooling is provided by mechanical draft wet cooling towers. After passing through the HTF side of the solar heat exchangers, the cooled HTF is recirculated through the solar field.

Historically, parabolic trough plants have been designed to use solar energy as the primary energy source to produce electricity. The plants can operate at full rated power using solar energy alone given sufficient solar input. During summer months, the plants typically operate for 10 to 12 hours a day at full-rated electric output. However, to date, all plants have been hybrid solar/fossil plants; this means they have a backup fossil-fired capability that can be used to supplement the solar output during periods of low solar radiation. In the system shown in Figure 1, the optional natural-gas-fired HTF heater situated in parallel with the solar field, or the optional gas steam boiler/reheater located in parallel with the solar heat exchangers, provide this capability. The fossil backup can be used to produce rated electric output during overcast or nighttime periods. Figure 1 also shows that thermal storage is a potential option that can be added to provide dispatchability.

Integrated Solar Combined Cycle System (ISCCS)

The ISCCS is a new design concept that integrates a parabolic trough plant with a gas turbine combined-cycle plant [2,3]. The ISCCS has generated much interest because it offers an innovative way to reduce cost and improve the overall solar-to-electric efficiency. A process flow diagram for an ISCCS is shown in Figure 2. The ISCCS uses solar heat to supplement the waste heat from the gas turbine in order to augment power generation in the steam Rankine bottoming cycle. In this design, solar energy is generally used to generate additional steam and the gas turbine waste heat is used for preheat and steam superheating. Most designs have looked at increasing the steam turbine size by as much as 100%. The ISCCS design will likely be preferred over the solar Rankine plant in regions where combined cycle plants are already being built.

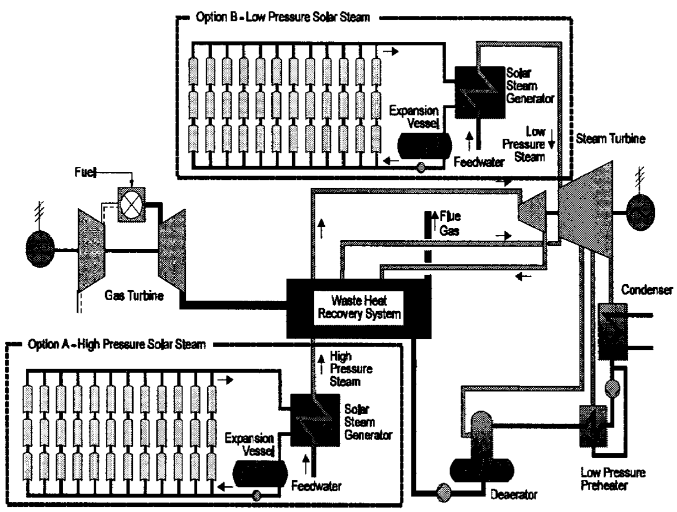

Figure 2. Integrated Solar Combined Cycle System [1].

SOLAR PARABOLIC TROUGH

Coal Hybrids

In regions with good solar resources where coal plants are currently used, parabolic trough plants can be integrated into the coal plant to either reduce coal consumption or add solar peaking, much like the ISCCS configuration. Due to the higher temperature and pressure steam conditions used in modern coal plants, the solar steam may need to be admitted in the intermediate or low-pressure turbine.

History

Organized, large-scale development of solar collectors began in the U.S. in the mid-1970s under the Energy Research and Development Administration (ERDA) and continued with the establishment of the U.S. Department of Energy (DOE) in 1978. Parabolic trough collectors capable of generating temperatures greater than 500°C (932°F) were initially developed for industrial process heat (IPH) applications. Much of the early development was conducted by or sponsored through Sandia National Laboratories in Albuquerque, New Mexico. Numerous process heat applications, ranging in size from a few hundred to about 5000 m^2 of collector area, were put into service. Acurex, SunTec, and Solar Kinetics were the key parabolic trough manufacturers in the United States during this period.

Parabolic trough development was also taking place in Europe and culminated with the construction of the IEA Small Solar Power Systems Project/Distributed Collector System (SSPS/DCS) in Tabernas, Spain, in 1981. This facility consisted of two parabolic trough solar fields with a total mirror aperture area of 7602 m^2. The fields used the single-axis tracking Acurex collectors and the double-axis tracking parabolic trough collectors developed by M.A.N. of Munich, Germany. In 1982, Luz International Limited (Luz) developed a parabolic trough collector for IPH applications that was based largely on the experience that had been gained by DOE/Sandia and the SSPS projects.

Although several parabolic trough developers sold IPH systems in the 1970s and 1980's, they generally found two barriers to successful marketing of their technologies. First, there was a relatively high marketing and engineering effort required for even small projects. Second, most potential industrial customers had cumbersome decision-making processes which often resulted in a negative decision after considerable effort had already been expended.

In 1983, Southern California Edison (SCE) signed an agreement with Acurex Corporation to purchase power from a solar electric parabolic trough power plant. Acurex was unable to raise financing for the project. Consequently, Luz negotiated similar power purchase agreements with SCE for the Solar Electric Generating System (SEGS) I and II plants. Later, with the advent of the California Standard Offer (SO) power purchase contracts for qualifying facilities under the Public Utility Regulatory Policies Act (PURPA), Luz was able to sign a number of SO contracts with SCE that led to the development of the SEGS III through SEGS IX projects. Initially, the plants were limited by PURPA to 30 MW in size; later this limit was raised to 80 MW. Table 1 shows the characteristics of the nine SEGS plants built by Luz.

In 1991, Luz filed for bankruptcy when it was unable to secure construction financing for its tenth plant (SEGS X). Though many factors contributed to the demise of Luz, the basic problem was that the cost of the technology was too high to compete in the power market. Lotker [5] describes the events that enabled Luz to successfully compete in the power market between 1984 and 1990 and many of the institutional barriers that contributed to their eventual downfall. It is important to note that all of the SEGS plants were sold to investor groups as independent power projects and continue to operate today.

SOLAR PARABOLIC TROUGH

Table 1. Characteristics of SEGS I through IX [4].

SEGS Plant	1st Year of Operation	Net Output (MW_e)	Solar Field Outlet Temp. (°C/°F)	Solar Field Area (m^2)	Solar Turbine Eff. (%)	Fossil Turbine Eff. (%)	Annual Output (MWh)
I	1985	13.8	307/585	82,960	31.5	-	30,100
II	1986	30	316/601	190,338	29.4	37.3	80,500
III & IV	1987	30	349/660	230,300	30.6	37.4	92,780
V	1988	30	349/660	250,500	30.6	37.4	91,820
VI	1989	30	390/734	188,000	37.5	39.5	90,850
VII	1989	30	390/734	194,280	37.5	39.5	92,646
VIII	1990	80	390/734	464,340	37.6	37.6	252,750
IX	1991	80	390/734	483,960	37.6	37.6	256,125

Collector Technology

The basic component of the solar field is the solar collector assembly (SCA). Each SCA is an independently tracking parabolic trough solar collector made up of parabolic reflectors (mirrors), the metal support structure, the receiver tubes, and the tracking system that includes the drive, sensors, and controls. Table 2 shows the design characteristics of the Acurex, single axis tracking M.A.N., and three generations of Luz SCAs. The general trend was to build larger collectors with higher concentration ratios (collector aperture divided by receiver diameter) to maintain collector thermal efficiency at higher fluid outlet temperatures.

Table 2. Solar collector characteristics [4,6].

Collector	Acurex 3001	M.A.N. M480	Luz LS-1	Luz LS-2		Luz LS-3
Year	1981	1984	1984	1985	1988	1989
Area (m^2)	34	80	128	235		545
Aperture (m)	1.8	2.4	2.5	5		5.7
Length (m)	20	38	50	48		99
Receiver Diameter (m)	0.051	0.058	0.042	0.07		0.07
Concentration Ratio	36:1	41:1	61:1	71:1		82:1
Optical Efficiency	0.77	0.77	0.734	0.737	0.764	0.8
Receiver Absorptivity	0.96	0.96	0.94	0.94	0.99	0.96
Mirror Reflectivity	0.93	0.93	0.94	0.94	0.94	0.94
Receiver Emittance	0.27	0.17	0.3	0.24	0.19	0.19
@ Temperature (°C/°F)			300/572	300/572	350/662	350/662
Operating Temp. (°C/°F)	295/563	307/585	307/585	349/660	390/734	390/734

Luz System Three (LS-3) SCA: The LS-3 collector was the last collector design produced by Luz and was used primarily at the larger 80 MW plants. The LS-3 collector represents the current state-of-the-art in parabolic trough collector design and is the collector that would likely be used in the next parabolic trough plant built. A more detailed description of the LS-3 collector and its components follows.

SOLAR PARABOLIC TROUGH

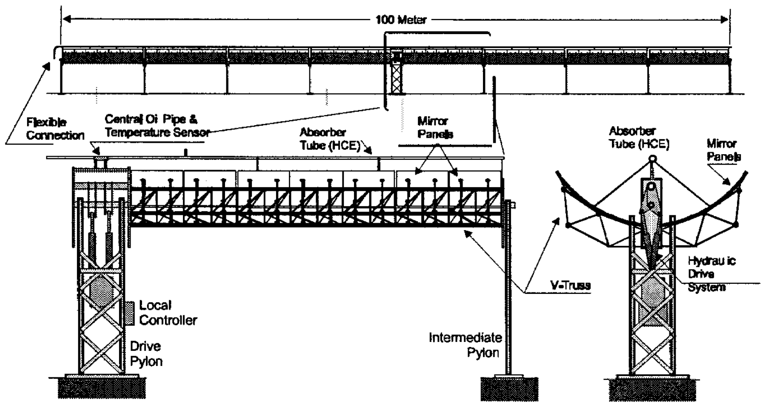

Figure 3. Luz System Three Solar Collector Assembly (LS-3 SCA) [1].

Figure 3 shows a diagram of the LS-3 collector. The LS-3 reflectors are made from hot-formed mirrored glass panels, supported by the truss system that gives the SCA its structural integrity. The aperture or width of the parabolic reflectors is 5.76 m and the overall SCA length is 95.2 m (net glass). The mirrors are made from a low iron float glass with a transmissivity of 98% that is silvered on the back and then covered with several protective coatings. The mirrors are heated on accurate parabolic molds in special ovens to obtain the parabolic shape. Ceramic pads used for mounting the mirrors to the collector structure are attached with a special adhesive. The high mirror quality allows 97% of the reflected rays to be incident on the linear receiver.

The linear receiver, also referred to as a heat collection element (HCE), is one of the primary reasons for the high efficiency of the Luz parabolic trough collector design. The HCE consists of a 70 mm steel tube with a cermet selective surface, surrounded by an evacuated glass tube. The HCE incorporates glass-to-metal seals and metal bellows to achieve the vacuum-tight enclosure. The vacuum enclosure serves primarily to protect the selective surface and to reduce heat losses at the high operating temperatures. The vacuum in the HCE is maintained at about 0.0001 mm Hg (0.013 Pa). The cermet coating is sputtered onto the steel tube to give it excellent selective heat transfer properties with an absorptivity of 0.96 for direct beam solar radiation, and a design emissivity of 0.19 at 350°C (662°F). The outer glass cylinder has anti-reflective coating on both surfaces to reduce reflective losses off the glass tube. Getters, metallic substances that are designed to absorb gas molecules, are installed in the vacuum space to absorb hydrogen and other gases that permeate into the vacuum annulus over time.

The SCAs rotate around the horizontal north/south axis to track the sun as it moves through the sky during the day. The axis of rotation is located at the collector center of mass to minimize the required tracking power. The drive system uses hydraulic rams to position the collector. A closed loop tracking system relies on a sun sensor for the precise alignment required to focus the sun on the HCE during operation to within +/- 0.1 degrees. The tracking is controlled by a local controller on each SCA. The local controller also monitors the HTF temperature and reports operational status, alarms, and diagnostics to the main solar field control computer in the control room. The SCA is designed for normal operation in winds up to 25 mph (40 km/h) and somewhat reduced accuracy in winds up to 35 mph (56 km/h). The SCAs are designed to withstand a maximum of 70 mph (113 km/h) winds in their stowed position (the collector aimed 30° below eastern horizon).

The SCA structure on earlier generations of Luz collectors was designed to high tolerances and erected in place in order to obtain the required optical performance. The LS-3 structure is a central truss that is built up in a jig and aligned precisely before being lifted into place for final assembly. The result is a structure that is both stronger and lighter. The truss is a pair of V-trusses connected by an endplate. Mirror support arms are attached to the V-trusses.

Availability of Luz Collector Technology: Although no new parabolic trough plants have been built since 1991, spare parts for the existing plants are being supplied by the original suppliers or new vendors. The two most critical and unique parts are the parabolic mirrors and the HCEs. The mirrors are being provided by Pilkington Solar International (PilkSolar) and are manufactured on the original SEGS mirror production line. The Luz HCE receiver tube manufacturing facility and technology rights were sold to SOLEL Solar Systems Ltd. of Jerusalem, Israel. SOLEL currently supplies HCEs as spare parts for the existing SEGS plants. Should a commercial opportunity arise, it is likely that a consortium of participants would form to supply Luz parabolic trough collector technology.

SEGS Plant Operating Experience

The nine operating SEGS plants have demonstrated the commercial nature of the Luz parabolic trough collector technology and have validated many of the SEGS plant design concepts. Additionally, many important lessons have been learned related to the design, manufacture, construction, operation, and maintenance of large-scale parabolic trough plants [7,8,9].

Solar Field Components: A simple problem with a single component, such as an HCE, can affect many thousands of components in a large solar field. Thus it is essential that each of the SCA components is designed for the 30-year life of the plant and that a sufficient QA/QC program is in place to ensure that manufacture and installation adhere to design specifications. Luz used three generations of collector during the development of the nine SEGS plants. Each time a new generation of collector was used, some form of component failure was experienced. However, one of the major achievements of Luz was the speed with which they were able to respond to new problems as they were identified. Problems with components were due to design or installation flaws. An important lesson from the plants has been the recognition that O&M requirements need to be fully integrated into the design. Three components in particular are worthy of discussion because they have represented the largest problems experienced: HCEs, mirrors, and flexhoses.

Heat Collection Elements (HCEs): A number of HCE failure mechanisms have been identified at the SEGS plants, with all of these issues resolved through the development of improved installation practices and operation procedures, or through a design modification. Loss of vacuum, breakage of the glass envelope, deterioration of the selective surface, and bowing of the stainless steel tube (which eventually can lead to glass breakage) have been the primary HCE failures, all of which affect thermal efficiency. Several of the existing SEGS plants have experienced unacceptably high HCE glass envelope breakage rates. The subsequent exposure to air accelerates degradation of the selective surface. Design improvements have been identified to improve durability and performance, and these have been introduced into replacement parts manufactured for the existing plants. In addition, better installation and operational procedures have significantly reduced HCE failures. Future HCE designs should: (1) use new tube materials to minimize bowing problems; (2) allow broken glass to be replaced in-situ in the field; and (3) continue to improve the selective coating absorptance, emittance, and long-term stability in air.

Mirrors: The current low iron glass mirrors are one of the most reliable components in the Luz collectors. Separation of the mirror mounting pads from the mirrors was an early problem caused by differential thermal expansion between the mirror and the pad. This problem was resolved by using ceramic pads, a more pliable adhesive, and thermal shielding. In addition, methods have been developed that allow the O&M crew to retrofit the older mirror pad design and strengthen them to greatly reduce failures. Mirror breakage due to high winds has been observed near the edges of the solar field where wind forces can be high. Strengthened glass mirrors or thin plastic silvered film reflectors have been designed to circumvent this problem. In general, there has been no long-term degradation in the reflective quality of the mirrors; ten year old mirrors can be cleaned and brought back to like-new reflectivity. However, the glass mirrors are expensive and for the cost of the collector to be reduced, alternative mirrors are necessary. Any new mirror must be able to be washed without damaging the optical quality of the mirror. Front surface mirrors hold potential to have higher reflectivity, if the long-term performance and washability can be demonstrated.

Flexhoses: The flexhoses that connect the SCAs to the headers and SCAs to each other have experienced high failure rates at the early SEGS plants. Later plants used an improved design with a substantially increased life that significantly reduced failures. In addition, a new design that replaces the flexhoses with a hard piped assembly with ball joints is being used at the SEGS III-VII plants located at Kramer Junction. The new ball joint assembly has a number of advantages over flexhoses including lower cost, a significant reduction in pressure drop, and reduced heat losses. If ball joint assemblies can be proven to have a life comparable to the new longer-life flexhoses, then they will be included in all future trough designs.

Mirror Washing & Reflectivity Monitoring: Development of an efficient and cost-effective program for monitoring mirror reflectivity and washing mirrors is critical. Differing seasonal soiling rates require flexible procedures. For example, high soiling rates of 0.5%/day have been experienced during summer periods. After considerable experience, O&M procedures have settled on several methods, including deluge washing, and direct and pulsating high-pressure sprays. All methods use demineralized water for good effectiveness. The periodic monitoring of mirror reflectivity can provide a valuable quality control tool for mirror washing and help optimize wash labor. As a general rule, the reflectivity of glass mirrors can be returned to design levels with good washing.

Maintenance Tracking: In recent years, computerized maintenance management software (CMMS) has found wide acceptance for use in conventional fossil power plant facilities. CMMS systems can greatly enhance the planning and efficiency with which maintenance activities are carried out, reduce maintenance costs, and often result in improved availability of the power plant. CMMS programs have been implemented at trough power plants as well, but the software is not ideally suited for the solar field portion of the plant. CMMS systems excel in applications that have a thousand unique pieces of equipment, but are not really suited to handle systems with a thousand of the same kind of equipment, like SCAs in a solar field. For this reason, custom database programs have been developed to track problems and schedule maintenance in the solar plant. These programs have proven to be an essential tool for tracking and planning solar field maintenance activities and should be considered to be essential for any new project.

Collector Alignment: Operational experience has shown that it is important to be able to periodically check collector alignment and to be able to correct alignment problems when necessary. Collector designs should allow field alignment checks and easy alignment corrections.

Project Start-up Support: Operation of a solar power plant differs from conventional fossil-fuel power plant operation in several ways, primarily due to the solar field equipment and operations requirements, integration of the solar field with the power block, and the effects of cyclic operation. Much knowledge has been gained from the existing SEGS plants that is applicable to the development of procedures, training of personnel, and the establishment of an effective O&M organization.

Thermal Cycling and Daily Startup: Typically, parabolic trough plants are operated whenever sufficient solar radiation exists, and the backup fossil is only used to fill in during the highest value non-solar periods. As a result, the plants are typically shut down during the night and restarted each morning. The plants must be designed to not only be started on a daily basis, but also to start up as quickly as possible. Since the current SEGS plant design does not include thermal storage, the solar field and power block are directly coupled. The use of thermal storage can significantly mitigate these problems. In general, equipment/system design specifications and operating procedures must be developed with these requirements in mind. Both normal engineering considerations and the experience from the SEGS plants provide important inputs into these needs. Mundane design features such as valves, gaskets, and seals and bolt selection can be an expensive problem unless properly specified.

2.0 System Application, Benefits, and Impacts

Large-scale Grid Connected Power: The primary application for parabolic trough power plants is large-scale grid connected power applications in the 30 to 300 MW range. Because the technology can be easily hybridized with fossil fuels, the plants can be designed to provide firm peaking to intermediate load power. The plants are typically a good match for applications in the U.S. southwest where the solar radiation resource correlates closely with peak electric power demands in the region. The existing SEGS plants have been operated very successfully in this fashion to meet SCE's summer on-peak time-of-use rate period. Figure 4 shows the on-peak performance of the SEGS III through SEGS VII plants that are operated by KJC Operating Company. The chart shows that all 5 plants have produced greater than 100% of their rated capacity during the critical on-peak period between 1200 and 1800 PDT on weekdays during June through September. This demonstrates the continuous high availability these plants have been able to achieve. Note that 1989 was the first year of operation for SEGS VI and SEGS VII.

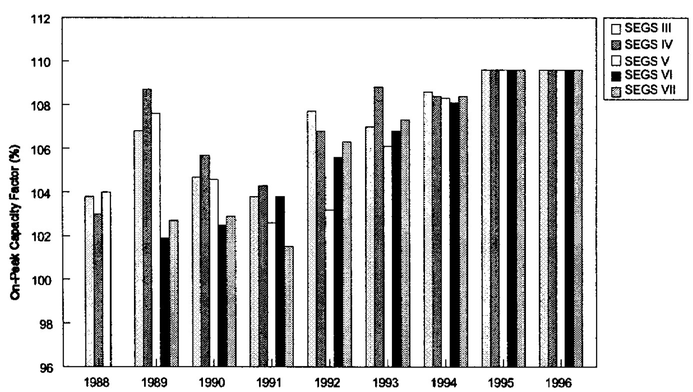

Figure 4. On-peak capacity factors for five 30 MW SEGS plants during 1988 to 1996 [10].

Domestic Market: The primary domestic market opportunity for parabolic trough plants is in the Southwestern deserts where the best direct normal solar resources exist. These regions also have peak power demands that could benefit from parabolic trough technologies. In particular, California, Arizona, and Nevada appear to offer some of the best opportunities for new parabolic trough plant development. However, other nearby states may provide excellent opportunities as well. The current excess of electric generating capacity in this region and the availability of low cost natural gas make future sustained deployment of parabolic trough technology in this region unlikely unless other factors come into play. However, with utility restructuring, and an increased focus on global warming and other environmental issues, many new opportunities such as renewable portfolio standards and the development of solar enterprise zones may encourage the development of new trough plants. All of the existing Luz-developed SEGS projects were developed as independent power projects and were enabled through special tax incentives and power purchase agreements such as the California SO-2 and SO-4 contracts.

SOLAR PARABOLIC TROUGH

International Markets: With the high demand for new power generation in many developing countries, the next deployment of parabolic troughs could be abroad. Many arid regions in developing countries are ideally suited for parabolic trough technologies. India, Egypt, Morocco, Mexico, Brazil, Crete (Greece), and Tibet (China) have expressed interest in trough technology power plants. Many of these countries are already planning installations of combined cycle projects. For these countries, the trough ISCCS design may provide a cheap and low risk opportunity to begin developing parabolic trough power plants. In regions such as Brazil and Tibet that have good direct normal solar resources and existing large hydroelectric and/or pumped storage generation resources, parabolic trough technologies can round out their renewable power portfolio by providing additional generation during the dry season.

Benefits

Least Cost Solar Generated Electricity: Trough plants currently provide the lowest cost source of solar generated electricity available. They are backed by considerable valuable operating experience. Troughs will likely continue to be the least-cost solar option for another 5-10 years depending on the rate of development and acceptance of other solar technologies.

Daytime Peaking Power: Parabolic trough power plants have a proven track record for providing firm renewable daytime peaking generation. Trough plants generate their peak output during sunny periods when air conditioning loads are at their peak. Integrated natural gas hybridization and thermal storage have allowed the plants to provide firm power even during non-solar and cloudy periods.

Environmental: Trough plants reduce operation of higher-cost, cycling fossil generation that would be needed to meet peak power demands during sunny afternoons at times when the most photochemical smog, which is aggravated by NO_X emissions from power plants, is produced.

Economic: The construction and operation of trough plants typically have a positive impact on the local economy. A large portion of material during construction can generally be supplied locally. Also trough plants tend to be fairly labor-intensive during both construction and operation, and much of this labor can generally be drawn from local labor markets.

Impacts

HTF Spills/Leaks: The current heat transfer fluid (Monsanto Therminol VP-1) is an aromatic hydrocarbon, biphenyl-diphenyl oxide. The oil is classified as non-hazardous by U.S. standards but is a hazardous material in the state of California. When spills occur, contaminated soil is removed to an on-site bio-remediation facility that utilizes indigenous bacteria in the soil to decompose the oil until the HTF concentrations have been reduced to acceptable levels. In addition to liquid spills, there is some level of HTF vapor emissions from valve packing and pump seals during normal operation [11]. Although the scent of these vapor emissions is often evident, the emissions are well within permissible levels.

Water: Water availability can be a significant issue in the arid regions best suited for trough plants. The majority of water consumption at the SEGS plants (approximately 90%) is used by the cooling towers. Water consumption is nominally the same as it would be for any Rankine cycle power plant with wet cooling towers that produced the same level of electric generation. Dry cooling towers can be used to significantly reduce plant water consumption; however, this can result in up to a 10% reduction in power plant efficiency. Waste water discharge from the plant is also an issue. Blowdown from the steam cycle, demineralizer, and cooling towers must typically be sent to a evaporation pond due to the high mineral content or due to chemicals that have been added to the water. Water requirements are shown in Section 5.

Land: Parabolic trough plants require a significant amount of land that typically cannot be used concurrently for other uses. Parabolic troughs require the land to be graded level. One opportunity to minimize the development of undisturbed lands is to use parcels of marginal and fallow agricultural land instead. A study sponsored by the California Energy Commission determined that 27,000 MW_e of STE plants could be built on marginal and fallow agricultural land in Southern California [12]. A study for the state of Texas showed that land use requirements for parabolic trough plants are less that those of most other renewable technologies (wind, biomass, hydro) and also less than those of fossil when mining and drilling requirements are included [13]. Current trough technology produces about 100 $kWh/yr/m^2$ of land.

Hybrid Operation: Solar/fossil hybrid plant designs will operate with fossil fuels during some periods. During these times, the plant will generate emissions consistent with the fuel.

3.0 Technology Assumptions and Issues

Trough Technology: The experience from the nine SEGS plants demonstrates the commercial nature of parabolic trough solar collector and power plant technologies. Given this experience, it is assumed that future parabolic trough plant designs will continue to focus on the Luz parabolic trough collector technology and Rankine cycle steam power plants. The next plants built are assumed to copy the 80 MW SEGS plant design and use the third generation Luz System Three parabolic trough collector.

Cost and Performance Data: The information presented is based on existing SEGS plant designs and operational experience. In addition, much of the cost data comes from PilkSolar [1] who has been actively pursuing opportunities for parabolic trough developments in many international locations. Performance projections assume a solar resource that would be typical for plants located in the California Mojave Desert. PilkSolar developed a detailed hour-by-hour simulation code to calculate the expected annual performance of parabolic trough plants. This model has been validated by baselining it against an operating SEGS plant. The model was found to reproduce real plant performance within 5% on an annual basis. The model can be used to perform design trade-off studies with a reasonable level of confidence.

Power Plant Size: Increasing plant size is one of the easiest ways to reduce the cost of solar electricity from parabolic trough power plants. Studies have shown that doubling the size reduces the capital cost by approximately 12-14% [1]. Figure 5 shows an example of how the levelized energy cost for solar electricity decreases by over 60% by only increasing the plant size. Cost reduction typically comes from three areas. First, the increased manufacturing volume of collectors for larger plants drives the cost per square meter down. Second, a power plant that is twice the size will not cost twice as much to build. Third, the O&M costs for larger plants will typically be less on a per kilowatt basis. For example, it takes about the same number of operators to operate a 10 MW plant as it does a 400 MW plant [2]. Power plant maintenance costs will be reduced with larger plants but solar field maintenance costs will scale more linearly with solar field size.

SOLAR PARABOLIC TROUGH

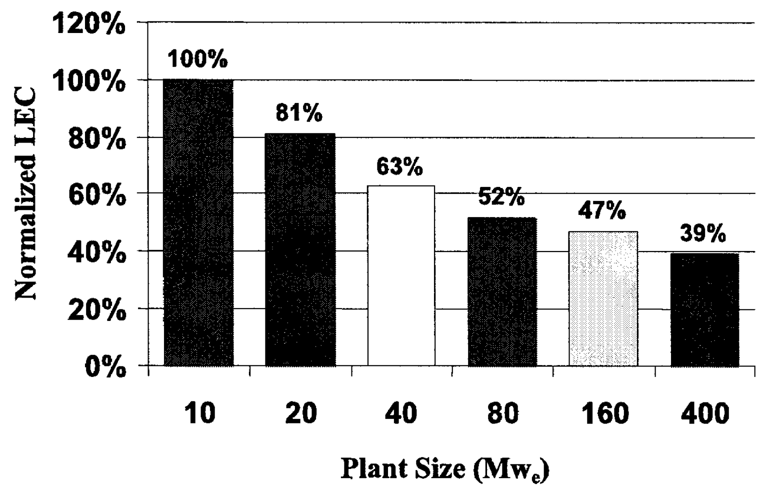

Figure 5. Effect of power plant size on normalized levelized COE.

The latest parabolic trough plants built were 80 MW in size. This size was a result of limitations imposed by the Federal government. Luz had investigated sizes up to 160 MW. The main concern with larger plants is the increased size of the solar field which impacts HTF pumping parasitics. In future plants, pumping parasitics will be reduced by replacing the flexible hoses with the new ball joint assemblies [8], allowing for plants in excess of the 160 MW size to be built.

Hybridization: Hybridization with a fossil fuel offers a number of potential benefits to solar plants including: reduced risk to investors, improved solar-to-electric conversion efficiency, and reduced levelized cost of energy from the plant [14]. Furthermore, it allows the plant to provide firm, dispatchable power.

Since fossil fuel is currently cheap, hybridization of a parabolic trough plant is assumed to provide a good opportunity to reduce the average cost of electricity from the plant. Hybridizing parabolic trough plants has been accomplished in a number of ways. All of the existing SEGS plants are hybrid solar/fossil designs that are allowed to take up to 25% of their annual energy input to the plant from fossil fuel. Fossil energy can be used to superheat solar generated steam (SEGS I), fossil energy can be used in a separate fossil-fired boiler to generate steam when insufficient solar energy is available (SEGS II-VII), or fossil energy can be used in an oil heater in parallel with the solar field when insufficient solar energy is available (SEGS VIII-IX). The decision on type of hybridization has been primarily an economic decision. However, it is clear from the SEGS experience that hybridization of the plants has been essential to the operational success of the projects.

The alternative ISCCS design offers a number of potential advantages to both the solar plant and the combined cycle plant. The solar plant benefits because the incremental cost of increasing the size of the steam turbine in the combined cycle is significantly less than building a complete stand-alone power plant. O&M costs are reduced because the cost of operation and maintenance on the conventional portion of the plant is covered by the combined cycle costs. Also, the net annual solar-to-electric efficiency is improved because solar input is not lost waiting for the turbine plant to start up, and because the average turbine efficiency will be higher since the turbine will always be running at 50% load or above. The combined cycle benefits because the fossil conversion efficiency is increased during solar operation since the gas turbine waste heat can be used more efficiently. Solar output will also help to offset the normal reduction in performance experienced by combined cycle plants during hot periods. Figure 6 shows how the LEC for an 80 MW solar increment ISCCS plant compares to those of a solar only SEGS and a conventional hybrid SEGS plant.

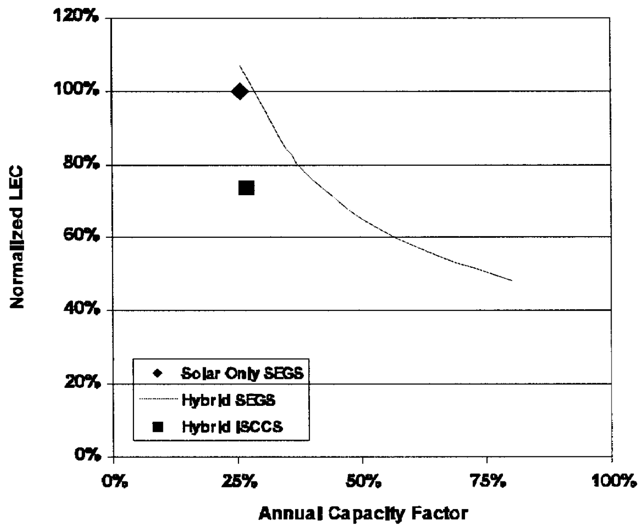

Figure 6. Effect of hybridization on LEC.

Thermal Storage: The availability of efficient and low-cost thermal storage is important for the long-term cost reduction of trough technology and significantly increases potential market opportunities. A parabolic trough plant with no fossil backup or thermal storage, located in the Mojave Desert, should be capable of producing electricity up to about a 25% annual capacity factor. The addition of thermal storage could allow the plant to dispatch power to non-solar times of the day and could allow the solar field to be oversized to increase the plant's annual capacity factor to about 50%. Attempting to increase the annual capacity factor much above 50% would result in significant dumping of solar energy during summer months. An efficient 2-tank HTF thermal storage system has been demonstrated at the SEGS I plant. However, it operates at a relatively low solar field HTF outlet temperature (307°C/585°F), and no cost effective thermal storage system has yet been developed for the later plants that operate at higher HTF temperatures (390°C/734°F) and require a more stable (and expensive) HTF. A study of applicable thermal storage concepts for parabolic trough plants has recommended a concrete and steel configuration, though other methods are possible [6].

Advanced Trough Collector: One of the main performance improvements possible for single axis tracking parabolic trough collectors is to tilt the axis of rotation above horizontal. Luz looked at tilting their LS-4 design 8° above horizontal and estimated a 9% increase in annual solar field performance.

Direct Steam Generation (DSG): In the DSG concept, steam is generated directly in the parabolic trough collectors. This saves cost by eliminating the need for the HTF system and reduces the efficiency loss of having to use a heat exchanger to generate steam. The solar field operating efficiency should improve due to lower average operating temperatures and improved heat transfer in the collector. The trough collectors require some modification due to the higher operating pressure and lower fluid flow rates. Control of a DSG solar field will likely be more complicated than the HTF systems and may require a more complex design layout and a tilted collector. DSG offers a number of advantages over current HTF systems, but controllability and O&M risks have yet to be resolved. A pilot demonstration of DSG technology is in progress at the Plataforma Solar de Almería in Spain [15].

Project Development Issues: The environment in which a trough project is developed will have a significant impact on the eventual cost of the technology. As mentioned in the Overview of Solar Thermal Technologies, building multiple plants in a solar power park environment, the type of project financing, and access to incentives which levelize the tax burden between renewables and conventional power technologies can dramatically improve the economics of STE technologies. Although project financing and tax equity issues are not addressed in this doccument, the technology cases presented in Section 4 assume that multiple projects are built at the same site in a solar power park environment. This assumption seems reasonable since a stand-alone plant would be significantly more expensive and less likely to be built.

Performance Adjustment Factor for Solar Radiation at Different Sites: Direct normal insolation (DNI) resources vary widely by location. The performance projections presented in the following sections assume a solar resource equivalent to Barstow, California. Table 3 shows the DNI resources for other locations [2,16] and the approximate change in performance that might be expected due to the different solar radiation resources. From Table 3 it can be seen that a 1% change in DNI results in a greater than 1% change in electric output. It is important to note that the table does not correct for latitude which can have a significant impact on solar performance. In general, solar field size can be increased to offset reduced performance resulting from lower clear sky radiation levels, but increased size cannot help reductions resulting from increased cloud cover, unless the plant also includes thermal storage.

4.0 Performance and Cost

Table 4 summarizes the performance and cost indicators for the parabolic trough system characterized in this report.

4.1 Evolution Overview

The parabolic trough plant technology discussion presented focuses on the development of Luz parabolic trough collector designs and the continued use of Rankine cycle steam power plants. Although the ISCCS concept is likely to be used for initial reintroduction of parabolic trough plants and could continue to be a popular design alternative for some time into the future, the approach used here is to look at how parabolic trough plants will need to develop if they are going to be able to compete with conventional power technologies and provide a significant contribution to the world's energy mix in the future. To achieve these long-term objectives, trough plants will need to continue to move towards larger solar only Rankine cycle plants and develop efficient and cost effective thermal storage to increase annual capacity factors.

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Table 3. Solar radiation performance adjustment.

Location	Site Latitude	Annual DNI (kWh/m^2)	Relative Solar Resource	Relative Solar Electric Output
United States				
Barstow, California	35°N	2,725	1.00	1.00
Las Vegas, Nevada	36°N	2,573	0.94	0.93
Tucson, Arizona	32°N	2,562	0.94	0.92
Alamosa, Colorado	37°N	2,491	0.91	0.89
Albuquerque, New Mexico	35°N	2,443	0.90	0.87
El Paso, Texas	32°N	2,443	0.90	0.87
International				
Northern Mexico	26-30°N	2,835	1.04	1.05
Wadi Rum, Jordan	30°N	2,500	0.92	0.89
Ouarzazate, Morocco	31°N	2,364	0.87	0.83
Crete	35°N	2,293	0.84	0.79
Jodhpur, India	26°N	2,200	0.81	0.75

<u>1997 Technology:</u> The 1997 baseline technology is assumed to be the 30 MW SEGS VI plant [17]. The SEGS VI plant is a hybrid solar/fossil plant that uses 25% fossil input to the plant on an annual basis in a natural gas-fired steam boiler. The plant uses the second generation Luz LS-2 parabolic trough collector technology. The solar field is composed of 800 LS-2 SCAs (188,000 m^2 of mirror aperture) arranged in 50 parallel flow loops with 16 SCAs per loop. Similar to the 80 MW plants, the power block uses a reheat steam turbine and the solar field operates at the same HTF outlet temperature of 390°C (734°F). Solar steam is generated at 10 MPa and 371°C (700°F). The plant is hybridized with a natural gas fired steam boiler which generates high pressure steam at 10 MPa and 510°C (950°F).

<u>2000 Technology:</u> The year 2000 plant is assumed to be the next parabolic trough plant built which is assumed to be the 80 MW SEGS X design [4]. The primary changes from the 1997 baseline technology is that this plant size increases to 80 MW, the LS-3 collector is used in place of the LS-2, the HCE uses an improved selective coating, and flex hoses have been replaced with ball joint assemblies. The solar field is composed of 888 LS-3 SCAs (510,120 m^2 of mirror aperture) arranged in 148 parallel flow loops with 6 SCAs per loop. The plant is hybridized with a natural gas fired HTF heater.

<u>2005 Technology:</u> The power plant is scaled up to 160 MW. Six hours of thermal storage is added to the plant to allow the plant to operate at up to a 40% annual capacity factor from solar input alone. No backup fossil operating capability is included. The LS-3 parabolic trough collector continues to be used, but the solar field size is scaled up to allow the plant to achieve higher annual capacity factor using 2,736 SCAs (1,491,120 m^2 of mirror aperture) arranged in 456 parallel flow loops with 6 SCAs per loop.

<u>2010 Technology:</u> The power plant is scaled up to 320 MW and operates to an annual capacity factor of 50% from solar input. Again no fossil backup operation is included. This design incorporated the next generation of trough

Table 4. Performance and cost indicators.

INDICATOR NAME	UNITS	1997 SEGS VI * Base Case	+/-%	2000 SEGS LS-3 25% Fossil †	+/-%	2005 SEGS LS-3 w/Storage	+/-%	2010 SEGS LS-4 w/Storage	+/-%	2020 SEGS DSG w/Storage	+/-%	2030 SEGS DSG w/Storage	+/-%
Plant Design													
Plant Size	MW	30		80		161		320		320		320	
Collector Type		LS-2		LS-3		LS-3		LS-4		LS-4		LS-4	
Solar Field Area	m^2	188,000		510,120		1,491,120		3,531,600		3,374,640		3,204,600	
Thermal Storage	Hours	0		0		6		10		10		10	
	MWh_t	0		0		3,000		10,042		9,678		9,678	
Performance													
Capacity Factor	%	34		34		40		50		50		50	
Solar Fraction (Net Elec.)	%	66		75		100		100		100		100	
Direct Normal Insolation	kWh/m^2-yr	2,891		2,725		2,725		2,725		2,725		2,725	
Annual Solar to Elec. Eff.	%	10.7		12.9		13.8		14.6		15.3		16.1	
Natural Gas (HHV)	GJ	350,000		785,000		0		0		0		0	
Annual Energy Production	GWh/yr	89.4		238.3		564.1		1,401.6		1,401.6		1,401.6	
Development Assumptions													
Plants Built Per Year		2		2		2		3		3		3	
Plants at a Single Site		5		5		5		5		5		5	
Competitive Bidding Adj.		1.0		1.0		0.9		0.9		0.9		0.9	
O&M Cost Adjustment		1.0		0.9		0.85		0.7		0.6		0.6	
Operations and Maintenance Cost													
Labor	$/kW-yr			32	25	21	25	14	25	11	25	11	25
Materials				31	25	31	25	29	25	23	25	23	25
Total O&M Costs		107		63		52		43		34		34	

Notes:

1. The columns for "+/- %" refer to the uncertainty associated with a given estimate.
2. The construction period is assumed to be 1 year.
3. Totals may be slightly off due to rounding.

* SEGS VI Capital cost of $99.3M in 1989$ is adjusted to $119.2M in 1997$. Limited breakdown of costs by subsystem is available. Performance and O&M costs based on actual data.

† By comparison, an ISCCS plant built in 2000 with an 80 MW solar increment would have a solar capital cost of $2,400/kW, annual O&M cost of $48/kW, and an annual net solar-to-electric efficiency of 13.5%[1].

‡ To convert to peak values, the effect of thermal storage must be removed. A first-order estimate can be obtained by dividing installed costs by the solar multiple (i.e., SM={peak collected solar thermal power}÷ {power block thermal power}).

Table 4. Performance and cost indicators.(cont.)

INDICATOR NAME	UNITS	1997 SEGS VI* Base Case	+/-%	2000 SEGS LS-3 25% Fossil†	+/-%	2005 SEGS LS-3 w/Storage	+/-%	2010 SEGS LS-4 w/Storage	+/-%	2020 SEGS DSG w/Storage	+/-%	2030 SEGS DSG w/Storage	+/-%
Capital Cost													
Structures/Improvements	\$/kW	54		79	15	66	15	62	15	60	15	58	15
Collector System		3,048		1,138	25	1,293	25	1,327	25	1,275	25	1,158	25
Thermal Storage System		0		0		392	+50/-25	528	+50/-25	508	+50/-25	508	+50/-25
Steam Gen or HX System				109	15	90	15	81	15	80	15	79	15
Aux Heater/Boiler		120		164	15	0	15	0	15	0	15	0	15
Electric Power Generation				476	15	347	15	282	15	282	15	282	15
Balance of Plant		750		202	15	147	15	120	15	120	15	120	15
Subtotal (A)		3,972		2,168		2,336		2,400		2,326		2,205	
Engr, Proj./Const. Manag.	A * 0.08			174		187		192		186		176	
Subtotal (B)		3,972		2,342		2,523		2,592		2,512		2,382	
Project/Process Conting	B * 0.15			351		378		389		377		357	
Total Plant Cost		3,972		2,693		2,901		2,981		2,889		2,739	
Land @ \$4,942/ha				11		15		18		17		17	
Total Capital Requirements	\$/kW	3,972		2,704		2,916		2,999		2,907		2,756	
	$\$/kW_{peak}$‡	3,972		2,704		1,700		1,400		1,350		1,300	
	$\$/m^2$	634		424		315		272		276		275	
Operations and Maintenance Cost													
Labor	\$/kW-yr			32	25	21	25	14	25	11	25	11	25
Materials				31	25	31	25	29	25	23	25	23	25
Total O&M Costs		107		63		52		43		34		34	

Notes:

1. The columns for "+/- %" refer to the uncertainty associated with a given estimate.
2. The construction period is assumed to be 1 year.
3. Totals may be slightly off due to rounding.

* SEGS VI Capital cost of \$99.3M in 1989\$ is adjusted to \$119.2M in 1997\$. Limited breakdown of costs by subsystem is available. Performance and O&M costs based on actual data.

† By comparison, an ISCCS plant built in 2000 with an 80 MW solar increment would have a solar capital cost of \$2,400/kW, annual O&M cost of \$48/kW, and an annual net solar-to-electric efficiency of 13.5%[1].

‡ To convert to peak values, the effect of thermal storage must be removed. A first-order estimate can be obtained by dividing installed costs by the solar multiple (i.e., SM={peak collected solar thermal power}÷{power block thermal power}).

collector, possibly something like the Luz LS-4 advanced trough collector (over 3,500,000 m^2 of mirror aperture). The solar field continues to use a heat transfer fluid but the collector is assumed to have a fixed tilt of 8°.

2020 - 2030 Technology: Power plant size is assumed to remain at 320 MW with 50% annual capacity factor. This design assumes the technology will incorporate direct steam generation (DSG) into the collector in the solar field (over 3,200,000 m^2 of mirror aperture).

4.2 Performance and Cost Discussion

Plant Performance

Increasing the performance of the solar collectors and power plant are one of the primary opportunities for reducing the cost of trough technology. Collector performance improvements can come from developing new more efficient collector technologies and components but often also by improving the reliability and lifetime of existing components. Table 4 shows the annual performance and net solar-to-electric efficiency of each of the technology cases described above.

The 1997 baseline case performance represents the actual 1996 performance of the 30 MW SEGS VI plant (its 8th year of operation). During 1996, the SEGS VI plant had an annual net solar-to-electric efficiency of 10.7% [10,18]. This performance was somewhat reduced by the high level of HCE breakage at the plant (5% with broken glass and 1% with lost vacuum). Since the HCE problems at SEGS VI are due to a design error that was later corrected, we assume that HCE breakage at future plants should remain below 1%, a number consistent with the experience at the SEGS V plant. The SEGS VI plant was selected as the baseline system because substantially more cost and performance data is available and more analysis of plant performance has been completed than at either of the existing 80 MW SEGS plants. Note, even though only 25% of the annual energy input to the plant comes from natural gas, since this energy is converted only at the highest turbine cycle efficiency, 34% of the annual electric output from the plant comes from gas energy.

The year 2000 technology shows a 20% improvement in net solar to electric efficiency over the 1997 baseline system performance. This is achieved by using current technologies and designs, by reducing HCE heat losses and electric parasitics. New HCEs have an improved selective surface with a higher absorptance and a 50% lower emittance. This helps reduce trough receiver heat losses by one third. The ball joint assemblies and the reduced number of SCAs per collector loop (6 for LS-3 versus 16 for LS-2 collectors) will reduce HTF pumping parasitics. Adjusting for reduced parasitics, improved HCE selective surface, and lower HCE breakage, a new 80 MW plant would be expected to have a net solar-to-electric efficiency of 12.9%.

The 2005 technology shows a 7% increase in efficiency primarily as a result of adding thermal storage. Thermal storage eliminates dumping of solar energy during power plant start-up and during peak solar conditions when solar field thermal delivery is greater than power plant capacity. Thermal storage also allows the power plant to operate independently of the solar field. This allows the power plant to operate near full load efficiency more often, improving the annual average power block efficiency. The thermal storage system is assumed to have an 85% round-trip efficiency. Minor performance improvements also result from scaling the plant up to 160 MW from 80 MW. Annual net solar-to-electric efficiency increases to 13.8% [1].

The 2010 technology shows a 6% increase in net solar-to-electric efficiency primarily due to the use of the tilted collector. Power plant efficiency improves slightly due to larger size of the 320 MW power plant. Thermal storage has been increased to 10 hours and the solar field size increased to allow the plant to operate up to a 50% annual capacity factor. As a result, more solar energy must be stored before it can be used to generate electricity, thus the 85% round-trip efficiency of the thermal storage system tends to have a larger impact on annual plant performance. The resulting annual net solar-to-electric efficiency increases to 14.6%.

The 2020 and 2030 technologies show 5% and 10% improvements in performance over the 2010 trough technology. The is due to the introduction of the direct steam generation trough collector technology. DSG improves the efficiency in the solar field and reduces equipment costs by eliminating the HTF system. Power cycle efficiency is assumed to improve due to higher solar steam temperatures. Solar parasitics are reduced through elimination of HTF pumps. Although feedwater must still be pumped through the solar field, it is pumped at a much lower mass flow rate. This design also assumes that a low cost thermal storage system with an 85% round-trip efficiency is developed for use with the DSG solar field. Conversion to the DSG collector system could allow the net solar-to-electric efficiency to increase to over 16% by 2030. The changes between 2020 and 2030 are assumed to be evolutionary improvements and fine tuning of the DSG technology.

Cost Reductions

Table 4 shows the total plant capital cost for each technology case on a $/kW/m^2 basis. The technology shows a 30% cost reduction on a $/kW basis and a 55% reduction on a $/m^2 basis. These cost reductions are due to: larger plants being built, increased collector production volumes, building projects in solar power park developments, and savings through competitive bidding. In general, the per kW capital cost of power plants decreases as the size of the plant increases. For trough plants, a 49% reduction in the power block equipment cost results by increasing the power plant size from 30 to 320 MW. The increased production volume of trough solar collectors, as a result of larger solar fields and multiple plants being built in the same year, reduces trough collector costs by 44%. Power parks allow for efficiencies in construction and cost reduction through competitive bidding of multiple projects. A 10% cost reduction is assumed for competitive bidding in later projects.

The annual operation and maintenance (O&M) costs for each technology are shown in Table 4. O&M costs show a reduction of almost 80%. This large cost reduction is achieved through increasing size of the power plant, increasing the annual solar capacity factor, operating plants in a solar power park environment, and continued improvements in O&M efficiencies. Larger plants reduce operator labor costs because approximately the same number of people are required to operate a 320 MW plant as are required for a 30 MW plant. The solar power park assumes that five plants are co-located and operated by the same company resulting in a 25% O&M savings through reduced overhead and improved labor and material efficiencies. In addition, about one third of the cost reduction is assumed to occur because of improved O&M efficiency resulting from improved plant design and O&M practices based on the results of the KJC O&M Cost Reduction Study [8].

Summary

The technology cases presented above show that a significant increase in performance and reduction in cost is possible for parabolic trough solar thermal electric technologies as compared with the 1997 baseline technology case. Figure 7 shows the relative impacts of the various cost reduction opportunities or performance improvements on the baseline system's levelized cost of energy. It is significant to note that the majority of the cost reduction opportunities do not require any significant technology development. Conversely, significant progress must be made in these non-technology areas if parabolic troughs are to be competitive with conventional power technologies and make any significant market penetration.

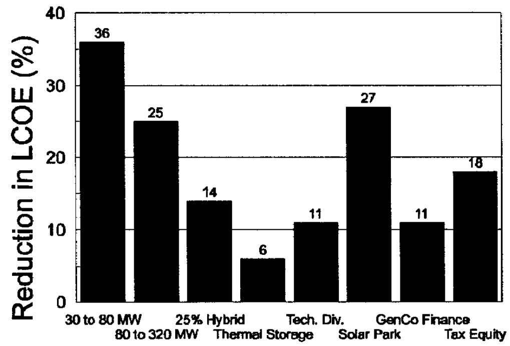

Figure 7. Cost reduction opportunities for parabolic trough plants.

5.0 Land, Water, and Critical Materials Requirements

Land and water requirements are shown in the table below for each of the technology cases. The land and water requirements initially increase as a result of increasing plant annual operating capacity factors. The land requirements begin to decrease as a result of improving solar-to-electric efficiencies. Note, the plant capacity factor increases over time because future plants are assumed to include thermal storage and proportionally larger solar fields.

Table 4. Resource requirements [2].

Indicator Name	Units	Base Year 1997	2000	2005	2010	2020	2030
Plant Size	MW	30	80	161	320	320	320
Land	ha/MW	2.2	2.2	3.1	3.7	3.6	3.4
	ha	66	176	500	1,190	1,150	1,090
Water	m^3/MW-yr	18,500	14,900	17,500	21,900	21,900	21,900

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SOLAR DISH ENGINE

1.0 System Description

Dish/engine systems convert the thermal energy in solar radiation to mechanical energy and then to electrical energy in much the same way that conventional power plants convert thermal energy from combustion of a fossil fuel to electricity. As indicated in Figure 1, dish/engine systems use a mirror array to reflect and concentrate incoming direct normal insolation to a receiver, in order to achieve the temperatures required to efficiently convert heat to work. This requires that the dish track the sun in two axes. The concentrated solar radiation is absorbed by the receiver and transferred to an engine.

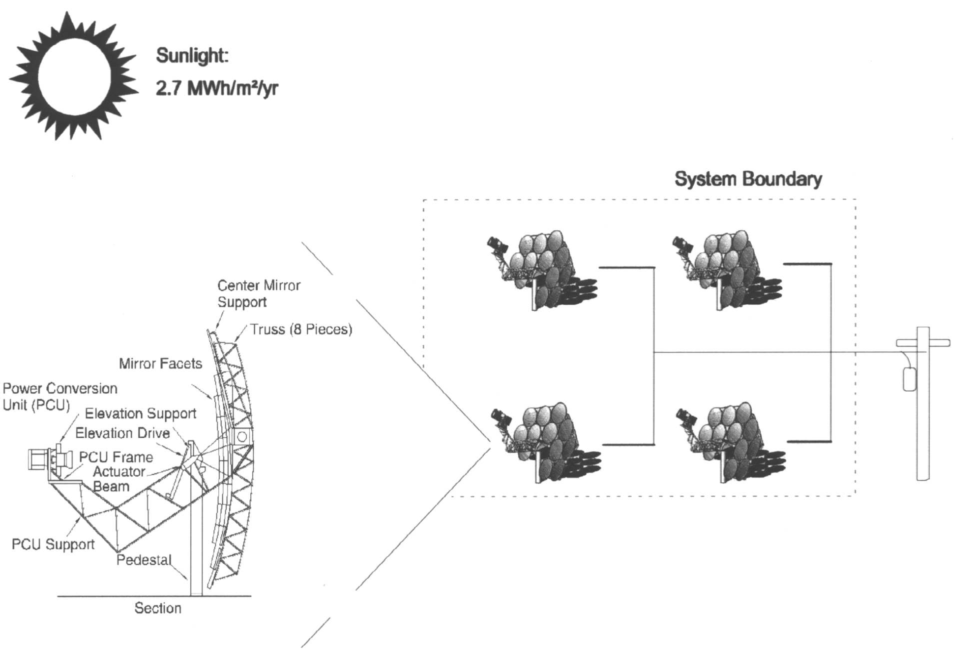

Figure 1. Dish/engine system schematic. The combination of four 25 kW_e units shown here is representative of a village power application

Dish/engine systems are characterized by high efficiency, modularity, autonomous operation, and an inherent hybrid capability (the ability to operate on either solar energy or a fossil fuel, or both). Of all solar technologies, dish/engine systems have demonstrated the highest solar-to-electric conversion efficiency (29.4%)[1], and therefore have the potential to become one of the least expensive sources of renewable energy. The modularity of dish/engine systems allows them to be deployed individually for remote applications, or grouped together for small-grid (village power) or end-of-line utility applications. Dish/engine systems can also be hybridized with a fossil fuel to provide dispatchable power. This technology is in the engineering development stage and technical challenges remain concerning the solar components and the commercial availability of a solarizable engine. The following describes the components of dish/engine systems, history, and current activities.

SOLAR DISH ENGINE

Concentrators

Dish/engine systems utilize concentrating solar collectors that track the sun in two axes. A reflective surface, metalized glass or plastic, reflects incident solar radiation to a small region called the focus. The size of the solar concentrator for dish/engine systems is determined by the engine. At a nominal maximum direct normal solar insolation of 1000 W/m^2, a 25-kW_e dish/Stirling system's concentrator has a diameter of approximately 10 meters.

Concentrators use a reflective surface of aluminum or silver, deposited on glass or plastic. The most durable reflective surfaces have been silver/glass mirrors, similar to decorative mirrors used in the home. Attempts to develop low-cost reflective polymer films have had limited success. Because dish concentrators have short focal lengths, relatively thin-glass mirrors (thickness of approximately 1 mm) are required to accommodate the required curvatures. In addition, glass with a low-iron content is desirable to improve reflectance. Depending on the thickness and iron content, silvered solar mirrors have solar reflectance values in the range of 90 to 94%.

The ideal concentrator shape is a paraboloid of revolution. Some solar concentrators approximate this shape with multiple, spherically-shaped mirrors supported with a truss structure (Figure 1). An innovation in solar concentrator design is the use of stretched-membranes in which a thin reflective membrane is stretched across a rim or hoop. A second membrane is used to close off the space behind. A partial vacuum is drawn in this space, bringing the reflective membrane into an approximately spherical shape. Figure 2 is a schematic of a dish/Stirling system that utilizes this concept. The concentrator's optical design and accuracy determine the concentration ratio. Concentration ratio, defined as the average solar flux through the receiver aperture divided by the ambient direct normal solar insolation, is typically over 2000. Intercept fractions, defined as the fraction of the reflected solar flux that passes through the receiver aperture, are usually over 95%.

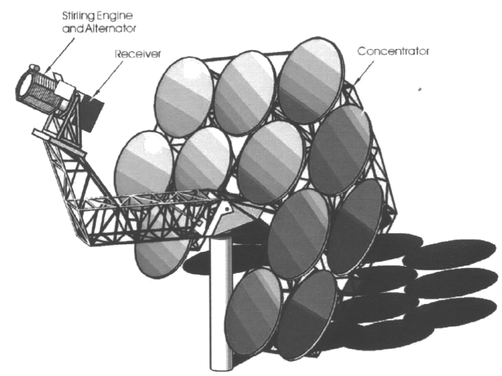

Figure 2. Schematic of a dish/engine system with stretched-membrane mirrors.

Tracking in two axes is accomplished in one of two ways, (1) azimuth-elevation tracking and (2) polar tracking. In azimuth-elevation tracking, the dish rotates in a plane parallel to the earth (azimuth) and in another plane perpendicular to it (elevation). This gives the collector left/right and up/down rotations. Rotational rates vary throughout the day but can be easily calculated. Most of the larger dish/engine systems use this method of tracking. In the polar tracking method, the collector rotates about an axis parallel to the earth's axis of rotation. The collector rotates at a constant rate of 15°/hr to match the rotational speed of the earth. The other axis of rotation, the declination axis, is perpendicular to the polar axis. Movement about this axis occurs slowly and varies by +/- 23½° over a year. Most of the smaller dish/engine systems have used this method of tracking.

Receivers

The receiver absorbs energy reflected by the concentrator and transfers it to the engine's working fluid. The absorbing surface is usually placed behind the focus of the concentrator to reduce the flux intensity incident on it. An aperture is placed at the focus to reduce radiation and convection heat losses. Each engine has its own interface issues. Stirling engine receivers must efficiently transfer concentrated solar energy to a high-pressure oscillating gas, usually helium or hydrogen. In Brayton receivers the flow is steady, but at relatively low pressures.

There are two general types of Stirling receivers, direct-illumination receivers (DIR) and indirect receivers which use an intermediate heat-transfer fluid. Directly-illuminated Stirling receivers adapt the heater tubes of the Stirling engine to absorb the concentrated solar flux. Because of the high heat transfer capability of high-velocity, high-pressure helium or hydrogen, direct-illumination receivers are capable of absorbing high levels of solar flux (approximately 75 W/cm^2). However, balancing the temperatures and heat addition between the cylinders of a multiple cylinder Stirling engine is an integration issue.

Liquid-metal, heat-pipe solar receivers help solve this issue. In a heat-pipe receiver, liquid sodium metal is vaporized on the absorber surface of the receiver and condensed on the Stirling engine's heater tubes (Figure 3). This results in a uniform temperature on the heater tubes, thereby enabling a higher engine working temperature for a given material, and therefore higher engine efficiency. Longer-life receivers and engine heater heads are also theoretically possible by the use of a heat-pipe. The heat-pipe receiver isothermally transfers heat by evaporation of sodium on the receiver/absorber and condensing it on the heater tubes of the engine. The sodium is passively returned to the absorber by gravity and distributed over the absorber by capillary forces in a wick. Receiver technology for Stirling engines is discussed in Diver et al. [2]. Heat-pipe receiver technology has demonstrated significant performance enhancements to an already efficient dish/Stirling power conversion module [3]. Stirling receivers are typically about 90% efficient in transferring energy delivered by the concentrator to the engine.

Solar receivers for dish/Brayton systems are less developed. In addition, the heat transfer coefficients of relatively low-pressure air along with the need to minimize pressure drops in the receiver make receiver design a challenge. The most successful Brayton receivers have used "volumetric absorption" in which the concentrated solar radiation passes through a fused silica "quartz" window and is absorbed by a porous matrix. This approach provides significantly greater heat transfer area than conventional heat exchangers that utilize conduction through a wall. Volumetric Brayton receivers using honeycombs and reticulated open-cell ceramic foam structures that have been successfully demonstrated, but for only short term operation (tens of hours) [4,5]. Test time has been limited by the availability of a Brayton engine. Other designs involving conduction through a wall and the use of fins have also been considered. Brayton receiver efficiency is typically over 80% [4,5].

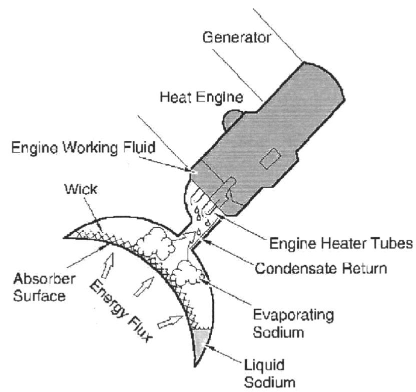

Figure 3. Schematic which shows the operation of a heat-pipe solar receiver.

Engines

The engine in a dish/engine system converts heat to mechanical power in a manner similar to conventional engines, that is by compressing a working fluid when it is cold, heating the compressed working fluid, and then expanding it through a turbine or with a piston to produce work. The mechanical power is converted to electrical power by an electric generator or alternator. A number of thermodynamic cycles and working fluids have been considered for dish/engine systems. These include Rankine cycles, using water or an organic working fluid; Brayton, both open and closed cycles; and Stirling cycles. Other, more exotic thermodynamic cycles and variations on the above cycles have also been considered. The heat engines that are generally favored use the Stirling and open Brayton (gas turbine) cycles. The use of conventional automotive Otto and Diesel engine cycles is not feasible because of the difficulties in integrating them with concentrated solar energy. Heat can also be supplied by a supplemental gas burner to allow operation during cloudy weather and at night. Electrical output in the current dish/engine prototypes is about 25 kW_e for dish/Stirling systems and about 30 kW_e for the Brayton systems under consideration. Smaller 5 to 10 kW_e dish/Stirling systems have also been demonstrated.

Stirling Cycle: Stirling cycle engines used in solar dish/Stirling systems are high-temperature, high-pressure externally heated engines that use a hydrogen or helium working gas. Working gas temperatures of over 700°C (1292°F) and as high as 20 MPa are used in modern high-performance Stirling engines. In the Stirling cycle, the working gas is alternately heated and cooled by constant-temperature and constant-volume processes. Stirling engines usually incorporate an efficiency-enhancing regenerator that captures heat during constant-volume cooling and replaces it when the gas is heated at constant volume. Figure 4 shows the four basic processes of a Stirling cycle engine. There are a number of mechanical configurations that implement these constant-temperature and constant-volume processes. Most involve the use of pistons and cylinders. Some use a displacer (a piston that displaces the working gas without changing its volume) to shuttle the working gas back and forth from the hot region to the cold region of the engine. For most engine designs, power is extracted kinematically by a rotating crankshaft. An exception is the free-piston configuration, where the pistons are not constrained by crankshafts or other mechanisms. They bounce back and forth on springs and the power is extracted from the power piston by a linear alternator or pump. A number of excellent references are available that describe the principles of Stirling machines. The best of the Stirling engines achieve

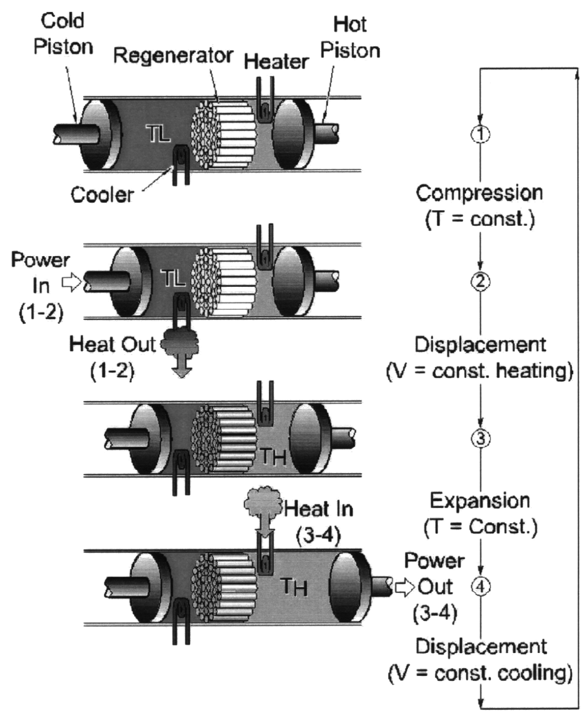

Figure 4. Schematic showing the principle of operation of a Stirling engine.

thermal-to-electric conversion efficiencies of about 40% [6-8]. Stirling engines are a leading candidate for dish/engine systems because their external heating makes them adaptable to concentrated solar flux and because of their high efficiency.

Currently, the contending Stirling engines for dish/engine systems include the SOLO 161 11-kW$_e$ kinematic Stirling engine, the Kockums (previously United Stirling) 4-95 25-kW$_e$ kinematic Stirling engine, and the Stirling Thermal Motors STM 4-120 25-kW$_e$ kinematic Stirling engine. (At present, no free-piston Stirling engines are being developed for dish/engine applications.) All of the kinematic Stirling engines under consideration for solar applications are being built for other applications. Successful commercialization of any of these engines will eliminate a major barrier to the introduction of dish/engine technology. The primary application of the SOLO 161 is for cogeneration in Germany; Kockums is developing a larger version of the 4-95 for submarine propulsion for the Swedish navy; and the STM4-120 is being developed with General Motors for the DOE Partnership for the Next Generation (Hybrid) Vehicle Program.

Brayton Cycle: The Brayton engine, also called the jet engine, combustion turbine, or gas turbine, is an internal combustion engine which produces power by the controlled burning of fuel. In the Brayton engine, like in Otto and Diesel cycle engines, air is compressed, fuel is added, and the mixture is burned. In a dish/Brayton system, solar heat is used to replace (or supplement) the fuel. The resulting hot gas expands rapidly and is used to produce power. In the gas turbine, the burning is continuous and the expanding gas is used to turn a turbine and alternator. As in the

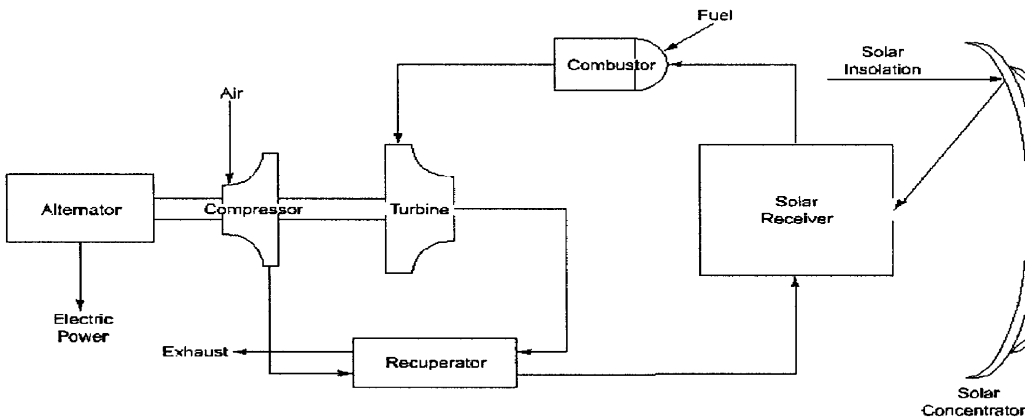

Figure 5. Schematic of a Dish/Brayton system.

Stirling engine, recuperation of waste heat is a key to achieving high efficiency. Therefore, waste heat exhausted from the turbine is used to preheat air from the compressor. A schematic of a single-shaft, solarized, recuperated Brayton engine is shown in Figure 5. The recuperated gas turbine engines that are candidates for solarization have pressure ratios of approximately 2.5, and turbine inlet temperatures of about 850°C (1,562°F). Predicted thermal-to-electric efficiencies of Brayton engines for dish/Brayton applications are over 30% [9,10].

The commercialization of similar turbo-machinery for various applications by Allied Signal, Williams International, Capstone Turbines Corp., Northern Research and Engineering Company (NREC), and others may create an opportunity for dish/Brayton system developers.

Ancillary Equipment

Alternator: The mechanical-to-electrical conversion device used in dish/engine systems depends on the engine and application. Induction generators are used on kinematic Stirling engines tied to an electric-utility grid. Induction generators synchronize with the grid and can provide single or three-phase power of either 230 or 460 volts. Induction generators are off-the-shelf items and convert mechanical power to electricity with an efficiency of about 94%. Alternators in which the output is conditioned by rectification (conversion to DC) and then inverted to produce AC power are sometimes employed to handle mismatches in speed between the engine output and the electrical grid. The high-speed output of a gas turbine, for example, is converted to very high frequency AC in a high-speed alternator, converted to DC by a rectifier, and then converted to 60 hertz single or three-phase power by an inverter. This approach can also have performance advantages for operation of the engine.

Cooling System: Heat engines need to transfer waste heat to the environment. Stirling engines use a radiator to exchange waste heat from the engine to the atmosphere. In open-cycle Brayton engines, most of the waste heat is rejected in the exhaust. Parasitic power required for operation of a Stirling cooling system fan and pump, concentrator drives, and controls is typically about 1 kW_e.

Controls: Autonomous operation is achieved by the use of microcomputer-based controls located on the dish to control dish tracking and engine operation. Some systems use a separate engine controller. For large installations, a central System Control and Data Acquisition (SCADA) computer is used to provide supervisory control, monitoring, and data acquisition.

History

Dish/engine technology is the oldest of the solar technologies, dating back to the 1800s when a number of companies demonstrated solar powered steam-Rankine and Stirling-based systems. Modern technology was developed in the late 1970s and early 1980s by United Stirling AB, Advanco Corporation, McDonnell Douglas Aerospace Corporation (MDA), NASA's Jet Propulsion Laboratory, and DOE. This technology used directly-illuminated, tubular solar receivers, the United Stirling 4-95 kinematic Stirling engine developed for automotive applications, and silver/glass mirror dishes. A sketch of the United Stirling Power Conversion Unit (PCU), including the directly illuminated receiver, is shown in Figure 6. The Advanco Vanguard system, a 25 kW_e nominal output module, recorded a record solar-to-electric conversion efficiency of 29.4% (net) using the United Stirling PCU [1,11]. This efficiency is defined as the net electrical power delivered to the grid, taking into account the electrical power needed for parasitics, divided by the direct normal insolation incident on the mirrors. MDA subsequently attempted to commercialize a system using the United Stirling PCU and a dish of their own design. Eight prototype systems were produced by MDA before the program was canceled in 1986 and the rights to the hardware and technology sold to Southern California Edison (SCE). The cancellation of the dish/Stirling program was part of MDA's decision to cancel all of their energy related activities, despite the excellent technical success of their dish/Stirling system. The MDA systems routinely converted sunlight incident on the concentrator's mirrors to electricity with net efficiencies of about 30%. Southern California Edison Company continued to test the MDA system on a daily basis from 1986 through 1988. During its last year of operation,

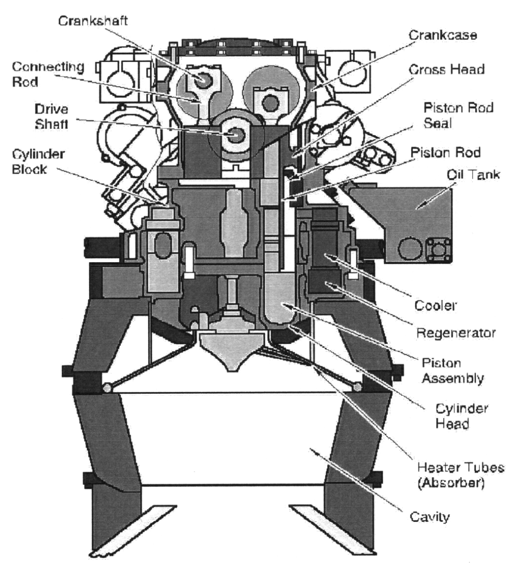

Figure 6. Schematic of the United Stirling 4-95 Kinematic Stirling engine.

it achieved an annual efficiency of about 12%, including system outages and all other effects such as mirror soiling. This is also a record for solar energy systems. Without outages, an annual efficiency of over 23% was determined to be achievable [12-15].

In the early 1990s, Cummins Engine Company attempted to commercialize dish/Stirling systems based on free-piston Stirling engine technology. The Cummins development efforts were supported by SunLab through two 50/50 cost shared contracts. (SunLab is a "virtual" laboratory composed of the solar thermal programs at Sandia National Laboratories and the National Renewable Energy Laboratory.) The Dish/Stirling Joint Venture Program (DSJVP) was started in 1991 and was intended to develop a 5 to 10 kW_e dish/Stirling system for remote power applications [16]. The Utility Scale Joint Venture Program (USJVP) was started in late 1993 with the goal of developing a 25 kW_e dish/engine system for utility applications [17]. However, largely because of a corporate decision to focus on its core diesel-engine business, Cummins canceled their solar development in 1996. Technical difficulties with Cummins' free-piston Stirling engines were never resolved [18].

Current Activities

In 1993, another USJVP contract was initiated with Science Applications International Corporation (SAIC) and Stirling Thermal Motors (STM) to develop a dish/Stirling system for utility-scale applications. The SAIC/STM team successfully demonstrated a 20-kW_e unit in Golden, Colorado, in Phase 1. In December 1996, Arizona Public Service Company (APS) partnered with SAIC and STM to build and demonstrate the next five prototype dish/engine systems in the 1997-1998 time frame. SAIC and Stirling Thermal Motors, Inc. (STM) are working on next-generation hardware including a third-generation version of the STM 4-120, a faceted stretched-membrane dish with a face-down-stow capability, and a directly-illuminated hybrid receiver. The overall objective is to reduce costs while maintaining demonstrated performance levels. Phase 3 of the USJVP calls for the deployment of one megawatt of dish/engine systems in a utility environment, which APS could then use to assist in meeting the requirements of Arizona's renewable portfolio standard.

The economic potential of dish/engine systems continues to interest developers and investors. For example, Stirling Energy Systems (SES) has purchased the rights of the MDA technology, including the rights to manufacture the Kockums 4-95 Stirling engine. SES is working with MDA to revive and improve upon the 1980s vintage system. There is also interest by Allied Signal Aerospace in applying one of their industrial Brayton engine designs to solar power generation. In response to this interest, DOE issued a request for proposal in the spring of 1997 under the Dish Engine Critical Components (DECC) initiative. The DECC initiative is intended to encourage "solarization" of industrial engines and involves major industrial partners.

Next-generation hybrid receiver technology based on sodium heat pipes is being developed by SunLab in collaboration with industrial partners. Although, heat-pipe receiver technology is promising and significant progress has been made, cost-effective designs capable of demonstrating the durability required of a commercial system still need to be proven. SunLab is also developing other solar specific technology in conjunction with industry.

2.0 System Application, Benefits, and Impacts

Dish/engine systems have the attributes of high efficiency, versatility, and hybrid operation. High efficiency contributes to high power densities and low cost, compared to other solar technologies. Depending on the system and the site, dish/engine systems require approximately 1.2 to 1.6 ha of land per MW_e. System installed costs, although currently over \$12,000/kW_e for solar-only prototypes could approach \$1,400/kW_e for hybrid systems in mass production (see

Section 4.0). This relatively low-cost potential is, to a large extent, a result of dish/engine system's inherent high efficiency.

Utility Application

Because of their versatility and hybrid capability, dish/engine systems have a wide range of potential applications. In principle, dish/engine systems are capable of providing power ranging from kilowatts to gigawatts. However, it is expected that dish/engine systems will have their greatest impact in grid-connected applications in the 1 to 50 MW_e power range. The largest potential market for dish/engine systems is large-scale power plants connected to the utility grid. Their ability to be quickly installed, their inherent modularity, and their minimal environmental impact make them a good candidate for new peaking power installations. The output from many modules can be ganged together to form a dish/engine farm and produce a collective output of virtually any desired amount. In addition, systems can be added as needed to respond to demand increases. Hours of peak output are often coincident with peak demand. Although dish/engine systems do not currently have a cost-effective energy storage system, their ability to operate with fossil or bio-derived fuels makes them, in principal, fully dispatchable. This capability in conjunction with their modularity and relatively benign environmental impacts suggests that grid support benefits could be a major advantage of these systems.

Remote Application

Dish/engine systems can also be used individually as stand-alone systems for applications such as water pumping. While the power rating and modularity of dish/engine systems seem ideal for stand-alone applications, there are challenges related to installation and maintenance of these systems in a remote environment. Dish/engine systems need to stow when wind speeds exceed a specific condition, usually at about 16 m/s. Reliable sun and wind sensors are therefore required to determine if conditions warrant operation. In addition, to enable operation until the system can become self sustaining, energy storage (e.g., a battery like those used in a diesel generator set) with its associated cost and reliability issues is needed. Therefore, it is likely that significant entry in stand-alone markets will occur after the technology has had an opportunity to mature in utility and village-power markets.

Intermediate-scale applications such as small grids (village power) appear to be well suited to dish/engine systems. The economies of scale of utilizing multiple units to support a small utility, the ability to add modules as needed, and a hybrid capability make the dish/engine systems ideal for small grids.

Hybridization

Because dish/engine systems use heat engines, they have an inherent ability to operate on fossil fuels. The use of the same power conversion equipment, including the engine, generator, wiring, switch gear, etc., means that only the addition of a fossil fuel combustor is required to enable a hybrid capability. For dish/Brayton systems, addition of a hybrid capability is straightforward. A fossil-fuel combustor capable of providing continuous full-power operation can be provided with minimal expense or complication. The hybrid combustor is downstream of the solar receiver, Figure 5, and has virtually no adverse impact on performance. In fact, because the gas turbine engine can operate continuously at its design point, where efficiency is optimum, overall system efficiency is enhanced. System efficiency, based on the higher heating value, is expected to be about 30% for a dish/Brayton system operating in the hybrid mode.

For dish/Stirling systems, on the other hand, addition of a hybrid capability is a challenge. The external, high-temperature, isothermal heat addition required for Stirling engines is in many ways easier to integrate with solar heat than it is with the heat of combustion. Geometrical constraints makes simultaneous integration even more difficult. As a result, costs for Stirling hybrid capability are expected to be on the order of an additional \$250/kW_e in large scale production. These costs are less than the addition of a separate diesel generator set, for a small village application, or a gas turbine for a large utility application. To simplify the integration of the two heat input sources, the first SAIC/STM hybrid dish/Stirling systems will operate on solar or gas, but not both at the same time. Although, the cost of these systems is expected to be much less than a continuously variable hybrid receiver, their operational flexibility will be substantially reduced. System efficiency, based on higher heating value, is expected to be about 33% for a dish/Stirling system operating in the hybrid mode.

Environmental Impacts

The environmental impacts of dish/engine systems are minimal. Stirling engines are known for being quiet, relative to internal combustion gasoline and diesel engines, and even the highly recuperated Brayton engines are reported to be relatively quiet. The biggest source of noise from a dish/Stirling system is the cooling fan for the radiator. There has not been enough deployment of dish/engine systems to realistically assess visual impact. The systems can be high profile, extending as much as 15 meters above the ground. However, aesthetically speaking they should not be considered detrimental. Dish/engine systems resemble satellite dishes which are generally accepted by the public. Emissions from dish/engine systems are also quite low. Other than the potential for spilling small amounts of engine oil or coolant or gearbox grease, these systems produce no effluent when operating with solar energy. Even when operating with a fossil fuel, the steady flow combustion systems used in both Stirling and Brayton systems result in extremely low emission levels. This is, in fact, a requirement for the hybrid vehicle and cogeneration applications for which these engines are primarily being developed.

3.0 Technology Assumptions and Issues

Dish/engine systems are not now commercially available, except as engineering prototypes. The base year (1997) technology is represented by the 25 kW_e dish-Stirling system developed by McDonnell Douglas Aerospace (MDA) in the mid 1980's using either an upgraded Kockums 4-95 or a STM 4-120 kinematic Stirling engine. The MDA system is similar in projected cost to the Science Applications International Corporation/Stirling Thermal Motors (SAIC/STM) dish/Stirling system, but has been better characterized. The SAIC/STM system is expected to have a peak net system efficiency of 21.9%. The SAIC/STM system uses stretched-membrane mirror modules that result in a lower intercept fraction and a higher receiver loss than the MDA system. However, the lower-cost stretched-membrane design and its improved operational flexibility are projected by SAIC to produce comparably priced systems [19].

Solar thermal dish/engine technologies are still considered to be in the engineering development stage. Assuming the success of current dish/engine joint ventures, these systems could become commercially available in the next 2 to 4 years. The base-year system consists of a dish concentrator that employs silver/glass mirror panels. The receiver is a directly-illuminated tubular receiver. As a result of extensive engineering development on the STM 4-120 and the Kockums engines, near-term technologies (year 2000 and 2005) are expected to achieve significant availability improvements for the engine, thus nearly doubling annual efficiency over the base year technology (from 12 to 23 %). For the years 2010 and on, systems are anticipated to benefit from evolutionary advances in dish concentrator and engine technology. For this analysis, a 10% improvement, compared to the base-year system, is assumed based on the introduction of heat-pipe receiver technology. The introduction of advanced materials and/or the incorporation of ceramics or volumetric absorption concepts could provide significant advances in performance compared to the baseline. Favorable development of advanced concepts could result in improvements of more than an additional 10%. However, because there are no significant activities in these areas, they are not included in this analysis.

SOLAR DISH ENGINE

The system characterized is located in a region of high direct normal insolation (2.7 MWh/m^2/yr), which is typified by the Mojave Desert of Southern California. Insolation is consistent with desert regions throughout the Southwest United States.

Research and Development Needs

The introduction of a commercial solar engine is the primary research and development (R&D) need for dish/engine technology. Secondary R&D needs include a commercially viable heat-pipe solar receiver for dish/Stirling, a hybrid-receiver design for dish/Stirling, and a proven receiver for dish/Brayton. All three of these issues are currently being addressed by SunLab and its partners, as part of the DOE Solar Thermal Electric Program. In addition, improvement in dish concentrator components, specifically drives, optical elements, and structures, are still needed and are also being addressed, albeit at a low level of effort. The solar components are the high cost elements of a dish engine system, and improved designs, materials, characterization, and manufacturing techniques are key to improving competitiveness.

Systems integration and product development are issues for any new product. For example, even though MDA successfully resolved many issues for their system, their methods may not apply or may not be available to other designs. Issues such as installation logistics, control algorithms, facet manufacturing, mirror characterization, and alignment methods, although relatively pedestrian, still need resolution for any design. Furthermore, if not addressed correctly, they can adversely affect cost. An important function of the Joint Ventures between SunLab and industry is to address these issues.

Advanced Development Opportunities

Beyond the R&D required to facilitate commercialization of the industrial derivative engines discussed above, there are high-payoff opportunities for engines designed exclusively for solar applications. The Advanced Stirling Conversion System (ASCS) program administered by the National Aeronautics and Space Administration (NASA) Lewis Research Center for DOE between 1986 and 1992, with the purpose of developing a high-performance free-piston Stirling engine/linear alternator, is an example of a high-risk high-payoff development [20]. An objective of the ASCS was to exploit the long life and reliability potential of free-piston Stirling engines.

Thermodynamically, solar thermal energy is an ideal match to Stirling engines because it can efficiently provide energy isothermally at high temperatures. In addition, the use of high-temperature ceramics or the development of "volumetric" Stirling receiver designs, in which a unique characteristic of concentrated solar flux is exploited, are other high-payoff R&D opportunities. Volumetric receivers exploit a characteristic of solar energy by avoiding the inherent heat transfer problems associated with conduction of high-temperature heat through a pressure vessel. Volumetric receivers avoid this by transmitting solar flux through a fused silica "quartz" window as light and can potentially work at significantly higher temperatures, with vastly extended heat transfer areas, and reduced engine dead volumes, while utilizing a small fraction of the expensive high-temperature alloys required in current Stirling engines. Scoping studies suggest that annual solar-to-electric conversion efficiencies in excess of 30% could be practically achieved with potentially lower cost "volumetric Stirling" designs. Similar performance enhancements can also be obtained by the use of high-temperature ceramic components.

SOLAR DISH ENGINE

4.0 Performance and Cost

Table 1 summarizes the performance and cost indicators for the solar dish/engine system being characterized here.

4.1 Evolution Overview

Over the next 5 to 10 years, only evolutionary advances are expected. The economic viability of dish/engine technology will be greatly enhanced if an engine capable of being "solarized" (i.e., integrated with solar energy) is introduced for another application. The best candidates are the STM 4-120 and the Kockums 4-95 kinematic Stirling engines for hybrid vehicles and industrial generators, and the industrial gas turbine/generators. Assuming one of these engines becomes commercial, then commercialization of dish/engine systems at some level becomes likely. With the costs and risks of the critical power conversion unit significantly reduced, only the concentrator, receiver, and controls would remain as issues. Given the operational experience and demonstrated durability and reliability of the remaining solar components, as well as the cost and performance capabilities of dish/engine technology, commercialization may appear attractive to some developers and investors. The modularity of dish/engine systems will help facilitate their introduction. Developers can evaluate prototype systems without the risks associated with multi-megawatt installations.

The commercialization of power towers and, therefore, heliostats (constructed of shared solar components), along with the introduction of a solarizable engine, would essentially guarantee a sizable and robust dish/engine industry. The added manufacturing volumes provided by such a scenario for the related concentrator drives, mirror, structural, and control components would significantly reduce costs and provide an attractive low-cost solar product that will compete in the 25 kW_e to 50 MW_e power market.

4.2 Performance and Cost Discussion

From the above discussion, one of three basic scenarios will happen: (1) no solarizable engine will be commercialized and, therefore, significant commercialization is unlikely, (2) a solarizable engine will be introduced, therefore spawning a fledgling dish/engine business or industry, and (3) a solarizable engine will be introduced and power tower projects will be initiated. Under this scenario, a large and robust solar dish/engine industry will transpire. Of course, numerous variations on the above scenarios are possible but are impossible to predict, much less consider. For the purpose of this analysis, the second scenario is assumed. The cost and performance data in the table reflect this scenario. As discussed in Section 3.0, a STM 4-120 or Kockums 4-95 is assumed to become commercial by 2000, with a dish/engine industry benefiting from mass production. This scenario is consistent with the commercialization plans of General Motors and STM for the STM 4-120.

Although a Brayton engine for industrial generator sets is also a potential positive development, the table considers a dish/Stirling system. A hybrid capability has been included in the table for the year 2000 and beyond. A capacity factor of 50% is assumed. This corresponds to a solar fraction of 50%.

The following paragraphs provide the basis for the cost and performance numbers in the table. System and component costs are from industry sources and independent SunLab analyses. Costs for the MDA system are from [15]. The installed costs include the cost of manufacturing the concentrator and power conversion unit (PCU), shipment to the site, site preparation, installation of the concentrator and PCU, balance of plant (connection to utility grid). The component costs include a 30% profit. These costs are similar to those projected by SAIC at the same

Table 1. Performance and cost indicators.

INDICATOR NAME	UNITS	1980's Prototype 1997	+/-%	Hybrid System 2000	+/-%	Commercial Engine 2005	+/-%	Heat Pipe Receiver 2010	+/-%	Higher Production 2020	+/-%	Higher Production 2030	+/-%
Typical Plant Size, MW	MW	0.025		1	50	30	50	30	50	30	50	30	50
Performance													
Capacity Factor	%	12.4		50.0		50.0		50.0		50.0		50.0	
Solar Fraction	%	100		50		50		50		50		50	
Dish module rating	kW	25.0		25.0		25.0		27.5		27.5		27.5	
Per Dish Power Production	MWh/yr/dish	27.4		109.6		109.6		120.6		120.6		120.6	
Capital Cost													
Concentrator	$/kW	4,200	15	2,800	15	1,550	15	500	15	400	15	300	15
Receiver		200	15	120	15	80	15	90	15	80	15	70	15
Hybrid		—		500	30	400	30	325	30	270	30	250	30
Engine		5,500	15	800	20	260	25	100	25	90	25	90	25
Generator		60	15	50	15	45	15	40	15	40	15	40	15
Cooling System		70	15	65	15	40	15	30	15	30	15	30	15
Electrical		50	15	45	15	35	15	25	15	25	15	25	15
Balance of Plant		500	15	425	15	300	15	250	15	240	15	240	15
Subtotal (A)		10,580		4,805		2,710		1,360		1,175		1,045	
General Plant Facilities (B)		220	15	190	15	150	15	125	15	110	15	110	15
Engineering Fee, 0.1*(A+B)		1,080		500		286		149		128		115	
Project /Process Contingency		0		0		0		0		0		0	
Total Plant Cost		11,880		5,495		3,146		1,634		1,413		1,270	
Prepaid Royalties		0		0		0		0		0		0	
Init Cat & Chem. Inventory		120	15	60	15	12	15	6	15	6	15	6	15
Startup Costs		350	15	70	15	35	15	20	15	18	15	18	15
Other		0		0		0		0		0		0	
Inventory Capital		200	15	40	15	12	15	4	15	4	15	4	15
Land, @$16,250/ha		26		26		26		26		26		26	
Subtotal		696		196		85		56		54		54	
Total Capital Requirement		12,576		5,691		3,231		1,690		1,467		1,324	
Total Capital Req. w/o Hybrid		12,576		5,191		2,831		1,365		1,197		1,074	
Operation and Maintenance Cost													
Labor	¢/kWh	12.00	15	2.10	25	1.20	25	0.60	25	0.55	25	0.55	25
Material	¢/kWh	9.00	15	1.60	25	1.10	25	0.50	25	0.50	25	0.50	25
Total	¢/kWh	21.00		3.70		2.30		1.10		1.05		1.05	

Notes:
1. The columns for "+/-%" refer to the uncertainty associated with a given estimate.
2. The construction period is assumed to be <1year for a MW scale system.

production rates [19]. These projections are also consistent with similar estimates by Cummins and with projections by SunLab engineers. Because of the proprietary nature of cost information, detailed breakdowns of cost estimates are not available in the public domain. Costs are also extremely sensitive to production rates. The installed costs are, therefore, extremely dependent on the market penetration actually achieved. Operation and Maintenance (O&M) costs are also based on [15]. They take into account realistic reliability estimates for the individual components. They are also reasonably consistent with O&M for the Luz trough plants and large wind farms. Component costs are a strong function of production rates. Production rate assumptions are also provided. The economic life of a dish/engine power plant is 30 years. The construction period is much less than one year.

1997 Technology

The base-year technology (1997) is represented by the 25 kW_e dish-Stirling system developed by McDonnell Douglas (MDA) in the mid 1980s. Similar cost estimates have been predicted for the Science Applications International Corporation (SAIC) system with the STM 4-120 Stirling engine [19]. Southern California Edison Company operated a MDA system on a daily basis from 1986 through 1988. During its last year of operation, it achieved an annual efficiency of 12% despite significant unavailability caused by spare part delivery delays. This annual efficiency is better than what has been achieved by all other solar electric systems, including photovoltaics, solar thermal troughs, and power towers, operating anywhere in the world [13,21). The base-year peak and daily performance of near-term technology are assumed to be that of the MDA systems. System costs assume construction of eight units. Operation and maintenance (O&M) costs are of the prototype demonstration and accordingly reflect the problems experienced.

2000 Technology

Near-term systems (2000) are expected to achieve significant availability improvements resulting in an annual efficiency of 23%. The MDA system consistently achieved daily solar efficiencies in excess of 23% when it was operational. The low availability achieved with the base-year technology was primarily caused by delays in receiving spare parts and by the lack of a dedicated O&M staff. A 23% annual efficiency is, therefore, a reasonable expectation, assuming Stirling engines are commercialized for other applications, and spare parts and a dedicated staff are available. In addition, near term technologies should see a modest reduction in the cost of the dish concentrator simply as a result of the benefits of an additional design iteration. Prototypes for these near-term technologies were first demonstrated in 1985 by McDonnell Douglas and United Stirling. Similar operational behavior was demonstrated in 1995 by SAIC and STM, although for a shorter test period and a lower system efficiency. O&M costs reflect improvements in reliability expected with the introduction of a commercial engine. Production of 100 modules is assumed. At this production rate, component costs are high, resulting in installed costs of nearly $\$5{,}700/kW_e$.

2005 Technology

Performance for 2005 is largely based on one of the solarizable engines being commercialized for a non-solar application (e.g., GM's introduction of the STM 4-120 Stirling engine for use in hybrid vehicles). Use of a production-level engine will have a significant impact on engine cost as well as overall system cost. This milestone will help trigger a fledgling dish/engine industry. A production rate of 2,000 modules per year is assumed. Achieving a high production rate is key to reducing component costs, especially for the solar concentrator.

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2010 Technology

Performance for years 2010 and beyond is based on the introduction of the heat-pipe solar receiver. Heat-pipe solar receiver development is currently being supported by SunLab in collaboration with industrial partners. The use of a heat-pipe receiver has already demonstrated performance improvements of well over 10% for the STM 4-120 compared to a direct-illumination receiver [1]. While additional improvements in mirror, receiver, and/or engine technology are not unreasonable expectations, they have not been included. This is, therefore, a conservative scenario. A production rate of 30,000 modules per year is assumed.

By 2010 dish/engine technology is assumed to be approaching maturity. A typical plant may include several hundred to over a thousand systems. It is envisioned that a city located in the U.S. Southwest would have several 1 to 50 MW_e installations located primarily in its suburbs. A central distribution and support facility could service many installations. In the table, a typical plant is assumed to be 30 MW_e.

2020-2030 Technology

Production levels for 2020 and 2030 are 50,000 and 60,000 modules per year, respectively. No major advances beyond the introduction of heat pipes in the 2010 time frame are assumed for 2020-2030. However, evolutionary improvements in mirror, receiver, and/or engine designs have been assumed. This is a reasonable assumption for a $2 billion/year, dish/engine industry, especially one leveraged by a larger automotive industry. The system costs are therefore 20 to 25% less than projected by MDA and SAIC at the assumed production levels. The MDA and SAIC estimates are for their current designs and do not include the benefits of a heat-pipe receiver. In addition, the MDA engine costs are for an engine that is being manufactured primarily for solar applications. Advanced concepts (e.g., volumetric Stirling receivers) and/or materials, which could improve annual efficiency by an additional 10%, have not been included in the cost projections. With these improvements installed costs of less than $1,000/$kW_e$ are not unrealistic.

5.0 Land, Water and Critical Materials Requirements

Land requirements for dish/engine systems are approximately 1.2-1.6 ha/MW_e. No water is required for engine cooling. In some locations, a minimal amount of water is required for mirror washing. There are no key materials that are unique to dish/engine technology.

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PROJECT FINANCIAL EVALUATION

Introduction to Financial Figures of Merit

An investor, energy policy analyst, or developer may use a variety of figures of merit to evaluate the financial attractiveness of a power project. The choice often depends on the purpose of the analysis. However, most begin with estimates of the project's capital cost, projected power output, and annual revenues, expenses, and deductions. A pro forma earnings statement, debt redemption schedule, and statement of after-tax cash flows are typically also prepared. Annual after-tax cash flows are then compared to initial equity investment to determine available return. For another perspective, before-tax, no-debt cash flows may also be calculated and compared to the project's total cost. The four primary figures of merit are:

Net Present Value: Net Present Value (NPV) is the sum of all years' discounted after-tax cash flows. The NPV method is a valuable indicator because it recognizes the time value of money. Projects whose returns show positive NPVs are attractive.

Internal Rate of Return: Internal rate of return (IRR) is defined as the discount rate at which the after-tax NPV is zero. The calculated IRR is examined to determine if it exceeds a minimally acceptable return, often called the hurdle rate. The advantage of IRR is that, unlike NPV, its percentage results allow projects of vastly different sizes to be easily compared.

Cost of Energy: To calculate a levelized cost of energy (COE), the revenue stream of an energy project is discounted using a standard rate (or possibly the project's IRR) to yield an NPV. This NPV is levelized to an annual payment and then divided by the project's annual energy output to yield a value in cents per kWh. The COE is often used by energy policy analysts and project evaluators to develop first-order assessments of a project's attractiveness. The levelized COE defines the stream of revenues that minimally meets the requirements for equity return and minimum debt coverage ratio. Traditional utility revenue requirement analyses are cost-based, ie., allowed costs, expenses, and returns are added to find a stream of revenues that meet the return criteria. Market-based Independent Power Producer (IPP) and Generating Company (GenCo) analyses require trial-and-error testing to find the revenues that meet debt coverage and equity return standards, but their COEs likewise provide useful information.

Payback Period: A payback calculation compares revenues with costs and determines the length of time required to recoup the initial investment. A Simple Payback Period is often calculated without regard to the time value of money. This figure of merit is frequently used to analyze retrofit opportunities offering incremental benefits and end-user applications.

Financial Structures

Four distinct ownership perspectives were identified for this analysis. Each reflects a different financial structure, financing costs, taxes, and desired rates of return. Briefly, the four ownership scenarios are:

Generating Company (GenCo): The GenCo takes a market-based rate of return approach to building, owning, and operating a power plant. The company uses balance-sheet or corporate finance, where debt and equity investors hold claim to a diversified pool of corporate assets. For this reason, GenCo debt and equity are less risky than for an IPP (see below) and therefore GenCos pay lower returns. A typical GenCo capital structure consists of 35% debt at a 7.5% annual return (with no debt service reserve or letter of credit required) and 65% equity at 13% return. Although corporate finance might assume the debt to equity ratio remains constant over the project's life and principal is never repaid, it is often informative to explicitly show the effect of the project on a stand-alone financial basis. Therefore, to be conservative, the debt term is estimated as 28 years for a 30-year project, and all the debt is repaid assuming level mortgage-style payments. Flow-through accounting is used so that the corporate GenCo receives maximum benefit from accelerated depreciation and tax credits.

Independent Power Producer (IPP): An IPP's debt and equity investment is secured by only the one project, not by a pool of projects or other corporate assets as is the case for a GenCo. In this project finance approach, a typical capital structure is 70% debt at 8.0% annual return (based on 30-year Treasury Bill return plus a 1.5% spread) and 30% equity at a minimum 17% return. A 6-month Debt Service Reserve is maintained to limit repayment risks. Debt term for an IPP project is generally 15 years, with a level mortgage-style debt repayment schedule. (For solar and geothermal projects that are entitled to take Investment Tax Credits, a capital structure of 60% debt and 40% equity should be considered.) Flow-through accounting is used to allow equity investors to realize maximum benefit from accelerated depreciation and tax credits. IPP projects are required to meet two minimum debt coverage ratios. The first requirement is to have an operating income of no less than 1.5 times the annual debt service for the worst year. The second is to have an operating income of about 1.8 times or better for the average year. Because debt coverage is often the tightest constraint, actual IRR may be well over 17%, to perhaps 20% or more. Likewise, with good debt coverage, negative after-tax cash flows in later years of debt repayment (phantom income) are low.

Regulated Investor-Owned Utility (IOU): The regulated IOU perspective analyzes a project with a cost-based revenue requirements approach. As described by the EPRI Technical Assessment Guide (TAG™), returns on investment are not set by the market, but by the regulatory system. In this calculation, operating expenses, property taxes, insurance, depreciation, and returns are summed to determine the revenue stream necessary to provide the approved return to debt and equity investors. Use of a Fixed Charge Rate is a way to approximate the levelized COE from this perspective. IOU capital structure is estimated as 47% debt at a 7.5% annual return; 6% preferred stock at 7.2%; and 47% common stock at 12.0%. Debt term and project life are both 30 years. Accelerated depreciation is normalized using a deferred tax account to spread the result over the project's lifetime. IOUs are not eligible to take an Investment Tax Credit for either solar or geothermal projects.

Municipal Utility (or other tax-exempt utility): The municipal utility uses an analysis approach similar to that of the IOU. Capital structure is, however, assumed to be 100% debt at 5.5% annual return, and the public utility pays neither income tax nor property tax.

Techniques for Calculating Levelized COE

The technique to be used for calculating levelized COE varies with ownership perspective. Two of the four ownership perspectives (IOU and Muni) employ a cost-based revenue requirements approach, while the other two use a market-based rate of return approach. The revenue requirements approach assumes a utility has a franchised service territory and, its rate of return is set by the state regulatory agency. The plant's annual expenses and cash charges are added to the allowed rate of return on the capital investment to determine revenues.

By contrast, the market-based approach (GenCo and IPP) either estimates a stream of project revenues from projections about electricity sales prices or proposes a stream as part of a competitive bid. Annual project expenses, including financing costs, are calculated and subtracted from revenues and an IRR is then calculated. The process of calculating the achieved IRR differs from the revenue requirements approach where the rate of return is pre-determined.

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COEs can be calculated for both revenue requirements and rate of return approaches. When pro forma cash flows in dollars of the day are projected for both approaches, the effects of general inflation are captured in debt repayment, income taxes, and other factors. Next, revenues are net present valued in current dollars. The NPV is then levelized to current dollars and/or constant dollars using appropriate discount rates for each. These are then levelized and normalized to one unit of energy production (kWh) to calculate current and constant dollar COEs. This document cites levelized constant dollar COEs in 1997 dollars.

Table 1 provides an example of the results that may be obtained for the technologies characterized in this document. The table shows levelized COE for the various renewable energy technologies assuming GenCo ownership and balance sheet finance.

Table 1. Levelized Cost of Energy for GenCo Ownership

		Levelized COE *(constant 1997 cents/kWh)*				
Technology	Configuration	1997	2000	2010	2020	2030
Dispatchable Technologies						
Biomass	Direct-Fired	8.7	7.5	7.0	5.8	5.8
	Gasification-Based	7.3	6.7	6.1	5.4	5.0
Geothermal	Hydrothermal Flash	3.3	3.0	2.4	2.1	2.0
	Hydrothermal Binary	3.9	3.6	2.9	2.7	2.5
	Hot Dry Rock	10.9	10.1	8.3	6.5	5.3
Solar Thermal	Power Tower	--	13.6*	5.2	4.2	4.2
	Parabolic Trough	17.3	11.8	7.6	7.2	6.8
	Dish Engine -- Hybrid	--	17.9	6.1	5.5	5.2
Intermittent Technologies						
Photovoltaics	Utility-Scale Flat-Plate Thin Film	51.7	29.0	8.1	6.2	5.0
	Concentrators	49.1	24.4	9.4	6.5	5.3
	Utility-Owned Residential (Neighborhood)	37.0	29.7	17.0	10.2	6.2
Solar Thermal	Dish Engine (solar-only configuration)	134.3	26.8	7.2	6.4	5.9
Wind	Advanced Horizontal Axis Turbines					
	- Class 4 wind regime	6.4	4.3	3.1	2.9	2.8
	- Class 6 wind regime	5.0	3.4	2.5	2.4	2.3

* COE is only for the solar portion of the year 2000 hybrid plant configuration.

PROJECT FINANCIAL EVALUATION

Financial Model and Results

The FATE2-P (Financial Analysis Tool for Electric Energy Projects) financial analysis model was used to analyze the data provided in the Technology Characterizations. This spreadsheet model was developed by Princeton Economic Research, Inc. and the National Renewable Energy Laboratory for the U.S. Department of Energy. FATE2-P can be used for either the revenue requirements or the discounted rate of return approach. It is used by the DOE renewable energy R&D programs for its planning activities. The model is publicly available, and has been used by a number of non-DOE analysts in recent studies. Other models will produce the same results given the same inputs.

The COEs in Table 1 were prepared using the FATE2-P model, assuming GenCo ownership. The results reflect a capital structure of 35% debt with a 7.5% return (with no debt service reserve or letter of credit required) and 65% equity at 13%. A 40% tax rate is assumed. Inflation was estimated at 3%, but electricity sales revenues were assumed to increase at inflation less one half percent, or 2.5%, corresponding to a real rate of -0.5%. In similar fashion, the Department of Energy's Annual Energy Outlook 1997 forecasts that retail electricity prices will decline by 0.6% real, assuming inflation of 3.1%. Anecdotal information from IPPs suggests that they also presently escalate their wholesale power prices at less than inflation.

Table 1 distinguishes between dispatchable and intermittent technologies to highlight the different services and value that each brings to the grid. COEs from the two types of services should not generally be compared.

By comparison, Table 2 shows COEs for year 2000 biomass gasification, to show how the financial requirements of the different ownership perspectives affect COE. The GenCo case is interesting to examine because it represents an evolving power plant ownership paradigm. The municipal utility (Muni) case is of interest because the lower cost of capital for Munis, combined with their tax-exempt status, makes them attractive early market opportunities for renewable energy systems.

Table 2. Cost of Energy For Various Ownership Cases for Biomass Gasification in Year 2000

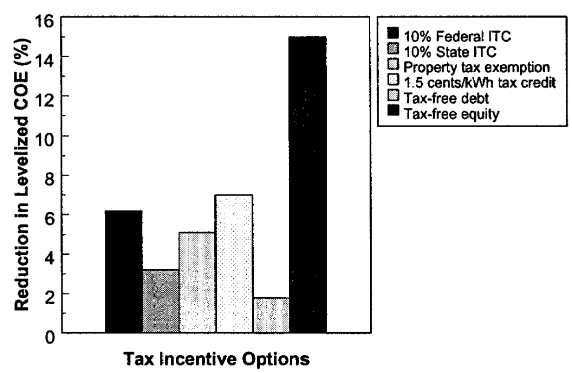
Financial Structure	Levelized Cost of Energy (constant 1997 cents/kWh)
GenCo	6.65
IPP	7.33
IOU	6.39
Muni	5.09

As discussed, calculating a levelized COE in the GenCo and IPP cases requires an iterative process. In this process, the goal is to identify the stream of revenues that is needed to ensure the project some minimally acceptable rate of return. This revenue stream is found by adjusting the assumption about first year energy payment (often termed the bid price) until the resulting total project revenues produce the required rate of return subject to meeting debt coverage requirements and minimizing phantom income for IPPs, and to meeting minimum equity returns for GenCos. In the analyses discussed here, the energy sales revenues are assumed to increase through the entire project life only at the rate of inflation minus one half percent (2.5%).

A few common assumptions underlie all the ownership/financing types. First, COE results are expressed in levelized *constant* 1997 dollars, consistent with the cost data in each TC, that are also stated in 1997 dollars. Second, general inflation is estimated at 3% per year, so annual expenses like operations and maintenance (O&M) and insurance escalate at 3% per year despite the fact that IPP and GenCo revenues increase at only 2.5%. Inflation also affects the values chosen for interest rates and equity returns. Tax calculations reflect an assumed 40% combined corporate rate (i.e.,

Tax Policy Analyses:
An Example Use of Financial Modeling

The effect of the tax code on the relative attractiveness of various electricity generating options can be analyzed by a financial model such as FATE2-P. A frequently mentioned goal of tax policy is to provide a "level playing field" for all technology options. One study, summarized in the figure, has shown that capital-intensive power projects, such as parabolic trough plants, pay a higher percentage of taxes than operating expense-intensive projects, such a fossil fuel technologies (through property taxes, sales taxes, etc.). Changes to the tax code have been suggested as a way to remove this potential bias.



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The graph shows the reduction in levelized energy cost for a number of possible tax system-based incentives. The 10% federal investment tax credit currently exists. The study cited in the figure compared taxes paid by solar thermal electric and fossil technologies. The analysis showed that approximate tax equity was achieved with a 20% federal investment tax credit and solar property tax exemption. Overall, this reduces levelized cost of energy by 20-30%. Although these results apply to the specific case tested, it shows the approximate level of tax incentives necessary to gain parity between solar thermal and conventional technologies. Since tax codes vary by state, each state could have a unique mix of additional tax incentives to provide incentives for solar for their unique tax environment.

federal at 35% and state at 7.7%, with state deductible from federal). In addition, depreciation periods and rates are those set by current law. Tax credits were used if set by law as permanent as of November 1997. Thus, the 10% Investment Tax Credit for solar and geothermal is included, but not the production tax credits for wind or closed loop biomass that are not available after mid-1999.

For the solar, dish hybrid cases and the early solar trough hybrid cases, the analyses in Table 1 assumed that natural gas costs $2.25/MMBtu in 1997 dollars and that it would escalate at 3% per year, equivalent to the inflation rate. The heat rate for the dish system was assumed to be 11,000 Btu/kWh in 2000 and 9000 Btu/kWh in 2005 and later. The trough TC included a heat rate in its hybrid system characterization.

Payback Period

For co-fired biomass a simple payback period was calculated instead of a levelized COE. As a retrofit opportunity, co-firing will be pursued by plant owners only if paybacks of a few years can be achieved. Simple Payback is defined as total capital investment divided by annual energy savings, to obtain years until payback. In simple payback, no consideration is given to the time value of money and no discount rates are applied to dollar values in future years. In the co-fire analyses, the simple payback is defined by comparing capital expenditures required for the retrofit with fuel cost and other savings. As an example, the technology described in the biomass co-fire technology characterization yields a 4.1-year payback in 2000.